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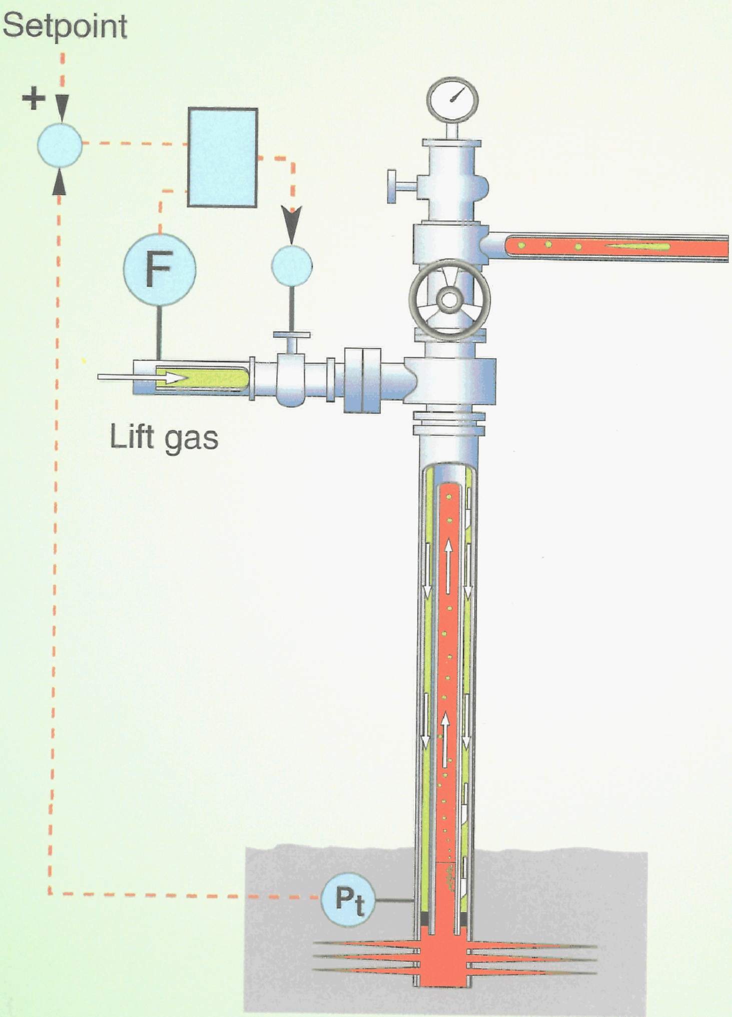
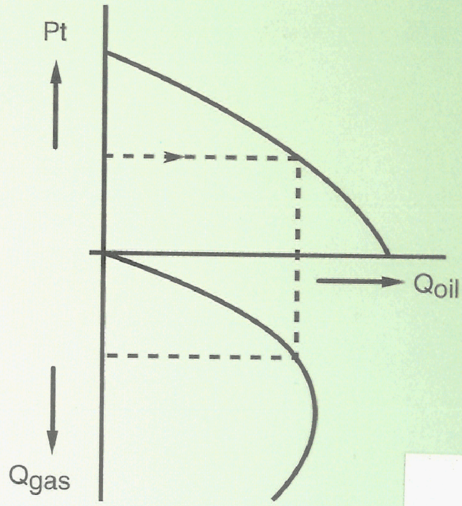
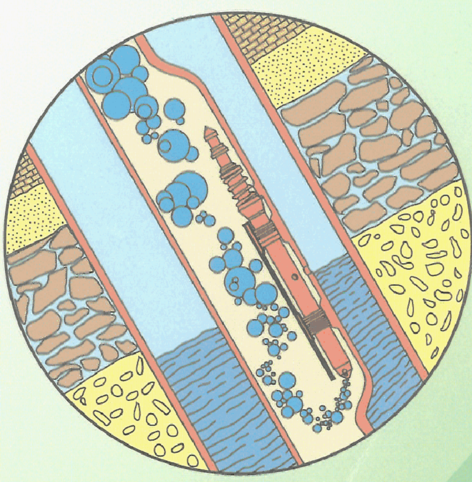
ARTIFICIAL LIFT MANUAL PART 2A

Gas Lift Design Guide







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ARTIFICIAL LIFT MANUAL PART 2A

Gas Lift Design Guide
Management of Artificial Lift Systems

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EXPLORATION AND PRODUCTION

FOREWORD

This document is primarily intended as an introduction to gas lift for Production Technology, Production Operations and Process Engineering staff involved in the design and operation of gas lifted production systems. The primary focus of the document is gas lift well behaviour and string design, although some attention has also been paid to gas lift system design and operation. It is also the intention that the guide will serve as the basis for Group training material.

Both continuous and intermittent lift systems are addressed, the guide however is mainly focused on continuous gas lift systems - as this is by far the most common method being employed within the Shell Group.

Since gas lift is an extension of natural flow, readers are expected to be familiar with the basic principles of:

- Hydrocarbon phase behaviour and multiphase flow
- Reservoir inflow performance
- Vertical flow and well performance
- Wellhead, choke and flow line performance.

These topics are covered in Volumes 5 and 7 of the SIPM Production Handbook [ref. 1]. For those unfamiliar with the above (and since it is fundamental to the understanding of gas lift), a brief recap of well performance is presented in Appendix A.

It is recognised that there are various gas lift design methods and procedures used both within Shell, and the industry as a whole. The fundamental approach outlined in this document will result in the technically optimum solution for most gas lift applications. Nevertheless, it is realised that local operating conditions and constraints may lead to this being challenged in search of a more cost effective alternative. Regardless of the methods used, the designer is urged to clearly and unambiguously record his design methods (and the underlying design and economic assumptions) in order to help efficient review and audit.

In this guide, important features of gas lift design are discussed, and the main design considerations highlighted. Evaluation methods are also covered, and use is made of worked examples to illustrate design principles. General recommendations are given where appropriate.

It should be stressed that the methodology and technical recommendations presented in this document are applicable to all potential green field and/or incremental gas lift projects - irrespective of their level of maturity.

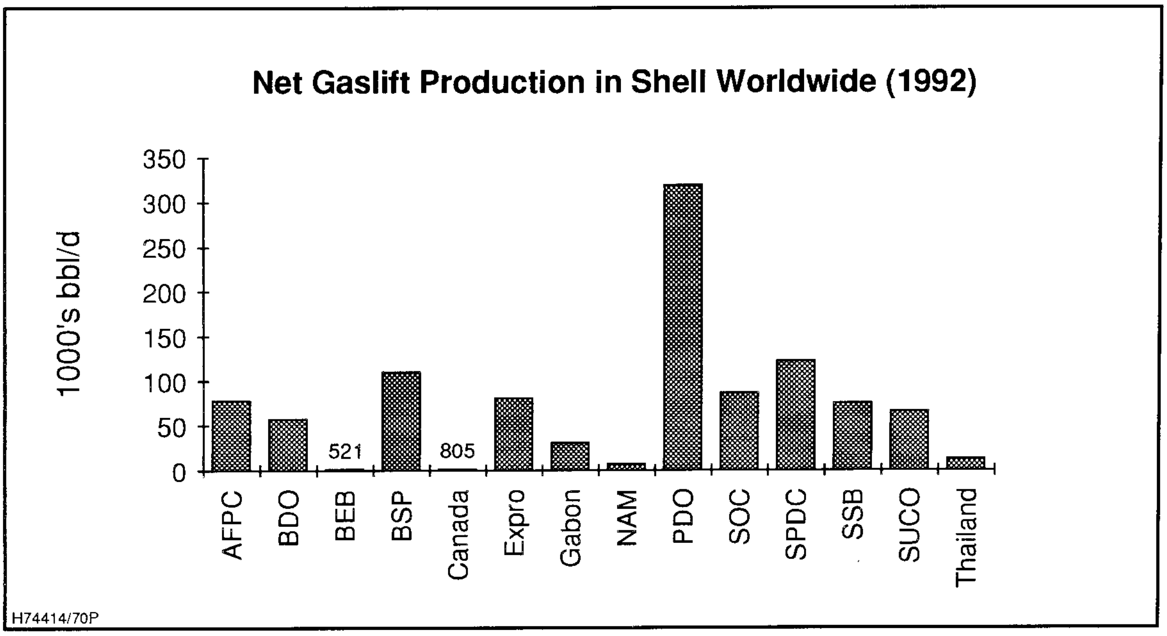
The Shell Group (probably more than any other E&P operator), collectively contains a wealth of experience in gas lift systems. It is imperative that this knowledge and expertise is collated, reviewed, and where appropriate incorporated into this document in order to add to the practical value. The basic material for this guide has been researched from a number of available sources, however there is also a significant amount of new material which is not generally available (valve performance, impact on design, computer assisted operations and a detailed discussion on current KSEPL research and well stability). As this is the first edition, users are strongly encouraged to critically feedback on the technical content and structure to SIPM EPD/414. Where applicable, staff are encouraged to channel feedback via the respective Opco gas lift/artificial lift champions.

A Word on Units

Throughout this document 'field' units have been used with very few exceptions. Currently this is the international language of gas lift. It did not seem appropriate to work with 'dual' units. For those readers who may be offended by this approach, our apologies in advance.

INTRODUCTION

Within the Group, gas lift is by far the most widely used form of artificial lift with gas lifted production levels in excess of 1 million bopd. This represents around 70% of the total Group artificially lifted production [ref. 2]. The figure below presents a summary of the main Group companies presently operating gas lift systems.



Opco gas lifted production.

Clearly gas lift system design and operation is, and will remain, a key activity in Field Development Planning and Production Operations.

The following chapter is intended to:

- Highlight the applicability and limitations of gas lift systems
- Review the gas lift design process, and emphasise the main gas lift design criteria that usually have greatest impact on project economics
- Review relevant design sensitivities
- Promote a total systems approach to gas lift design and operation.

The remainder of the document serves as a design guideline with respect to the basic elements of gas lift system design, performance surveillance, trouble shooting and production optimisation & control.

1. BASIC PRINCIPLES OF GAS LIFT

Transport of fluids from the reservoir to the surface requires work to be done. The necessary energy to perform this work may be contained in the reservoir. However, if the reservoir energy is insufficient to obtain the desired flow rate, reservoir energy may be supplemented from an external source. This is the fundamental principle of all artificial lift methods.

Gas lift is the continuous or intermittent injection of gas into the lower section of the production tubing to sustain, or increase, well potential. The injected gas is commingled with produced fluids, thereby decreasing the flowing gradient, enabling wells to be operated at reduced flowing bottom hole pressure, hence increasing or sustaining production (see Section 2.1).

In gas lift, the additional work required to increase the production rate of the well is performed at the surface by a gas compressor or contained in a high pressure gas stream conveyed to the well in the form of gas pressure energy.

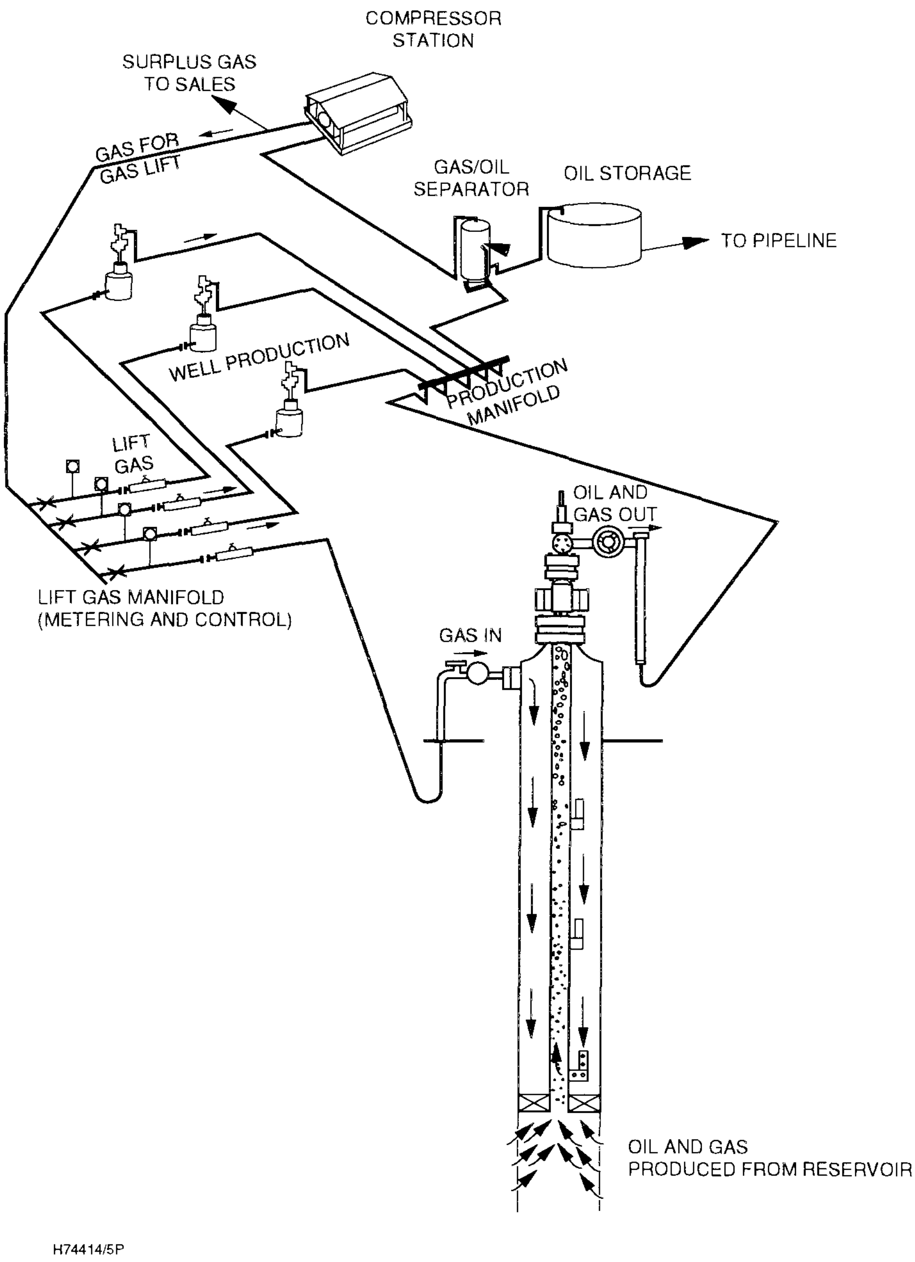


Figure 1.1. - A typical continuous gas lift system.

Figure 1.1. illustrates a continuous (rotative) gas lift system, where associated gas is used. A source of produced gas (up to 5-10% of system capacity, mainly for fuel) is required to sustain this 'closed loop' cycle.

1.1. Golden Rules of Gas Lift

When investigating the feasibility of a potential gas lift project, or reviewing the performance of an existing gas lift facility, the Production Technologist, Process Engineer and Production Operations Engineer should be fully aware of the system prerequisites - the 'golden rules' of gas lift:

- The success of any gas lift system depends on an adequate and reliable source of 'quality' lift gas throughout the period when gas lift is required.
- The gas injection point should be as close as possible to the top of the completion interval. In this respect, the equilibrium curve concept should be used as the basis of all gas lift design studies.
- Lift should be as stable as possible.
- Gas lift systems should operate with minimum (practical) back pressure at the wellhead.
- Completions should be designed for single-point lift.
- Lift gas availability should be optimised to enable the system to operate near-continuously in the most profitable configuration (e.g. minimise compressor down time).
- All gas lift system designs should address future, as well as present, operating conditions.
- Overly conservative design assumptions should be avoided - design factors should reflect the availability and quality of design data.
- Surveillance and control (SCADA/CAO/DCS) should be considered as an integral part of any gas lift system. Good quality data is a prerequisite for an efficient gas lift design. The ability to control gas distribution is essential for efficient gas lift operation.
- Gas lift clearly requires a 'systems think' approach in order to identify bottlenecks in production, disposal or flare systems.
- Gas lift systems should be designed with all modes of operation in mind (e.g. start up, turn down).

1.2. Types of Gas Lift

There are two basic gas lift systems used by Group companies:

1.2.1. Continuous Gas Lift

Is where gas is continuously injected into the well to gasify the liquid stream, with the objective of lightening the liquid column - and therefore increasing drawdown on the formation. This has the result of increasing the well GLR. This method is only applicable to wells having a lower than optimum natural GLR, and a reservoir pressure high enough to sustain the desired flow rate when the GLR is increased. Figure 1.1 shows a typical layout of a well and the surface facilities in a field producing on continuous gas lift.

Since gas injection pressures are normally much lower than the static reservoir pressure, gas lift valves are installed in the string to enable the well to be progressively unloaded, thereby establishing the operating injection depth as deep as possible. Gas lift string design, discussed in Chapter 4, is concerned with the correct positioning and operation of the selected valves, taking into account anticipated operating conditions.

Continuous gas lift systems are extensively utilised within the Shell Group, and account for more than 95% of Group gas lifted production. Continuous gas lift systems are further discussed in Section 2.1.

1.2.2. Intermittent Gas Lift

Is where gas is injected under a column of liquid (usually above a standing valve) to displace that slug of liquid to surface. This operation is repeated as soon as a sufficiently large liquid slug has accumulated again. The limitations of intermittent gas lift are mainly related to the 'cycle time' which can be achieved between successive slug production, and the volume of liquid that can be efficiently lifted as a slug; gas tends to break through the slug, and part of the liquid falls back. Controlling parameters are the inflow performance, the length and diameter of the conduit, the gas pressure, gas injection rate, and the length, weight and viscosity of the liquid slug. The introduction of a solid interface (plunger) between the gas and the liquid is a logical step to decrease liquid fall back. This alternative is known as plunger lift and also as PAIL (Plunger Assisted Intermittent Lift). Plunger lift may be an attractive alternative to beam pumping for wells which are no longer efficient under continuous or intermittent gas lift. A small number of these installations are in operation in the Group. Intermittent and plunger lift are discussed in more detail in Section 2.2.

1.3. Applicability and Features of Gas Lift

This section briefly discusses the general applicability of gas lift installations, and illustrates typical operating conditions of gas lift systems employed by Group companies. The major pro's and con's of gas lift are also reviewed.

1.3.1. Gas Lift Operating Envelope

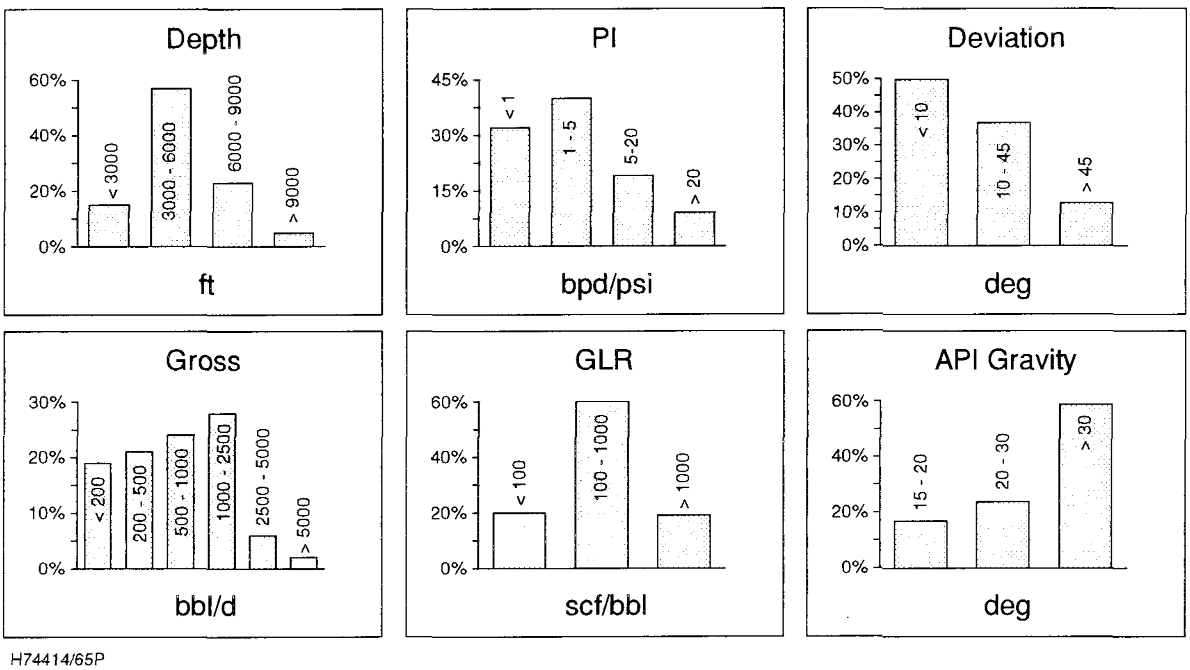


Figure 1.2. - Gas lift operating conditions within the Shell Group as a percentage of total gas lifted strings.

Gas lift has found widespread application within the Group due to the overall applicability and versatility compared to alternative pumping techniques. Figure 1.2 taken from [ref. 2] shows the range of operation of the gas lift systems used within the Group. This however, does not indicate the limits of gas lift.

Good quality data is considered invaluable when designing an artificial lift system [ref. 3]. It is realised that such data is not always readily available, as individual wells are seldom production tested prior to the completion phase. Nevertheless, it is well known [refs. 4, 5] that, relative to other forms of artificial lift, gas lift is much more 'forgiving' with respect to specification errors, improper design assumptions and changing operating conditions. This intrinsic design and operating flexibility is used in many instances to help justify the selection of gas lift in the first place. This is particularly true in areas where uncertainty surrounds reservoir production mechanisms and well performance in the early stages of field development. The 'down side' of this is that gas lift systems can be operated inefficiently (from necessity or by lack of good system surveillance) for long periods of time - often resulting in significant production deferral.

1.3.2. Limitations of Gas Lift

Notwithstanding the clear advantages of gas lift in terms of flexibility, when comparing gas lift installations with other forms of artificial lift, a number of distinct limitations become apparent:

- An adequate and reliable source of gas is required throughout the life of the development. Moreover, if the source gas is poor (e.g. low pressure, wet, corrosive), significant incremental expenditure will be required to install, and maintain, a gas conditioning plant. This can be less of a problem than in the past as most new developments now include gas treatment for sales or re-injection.
- Continuous gas lift is unable to reduce intake pressures to 'pump off'. As a result of the physical process, gas lift is unable to reach very low bottom hole pressures. This will result in higher back pressure on the reservoir compared to other pumping methods, thereby restricting production potential - and even placing a limit on ultimate recovery. This problem becomes more evident with increasing depth and declining reservoir pressure.

The main pros and cons of gas lift are summarised below:

Pros

- ✓ Gas lift can operate over a wide range of producing conditions.
- ✓ Significant amounts of foreign material can be safely handled (e.g. sand).
- ✓ Gas lift has inherent gas handling capability, a severe drawback with many other forms of artificial lift.
- ✓ Systems can be designed to be low profile and unobtrusive. Offshore installations are relatively common.
- ✓ Well intervention / accessibility is excellent (usually full bore access) for well surveillance and remedial work (PLT, BHP, re-perforating etc. ...).
- ✓ Gas lift can be applied to any well configuration (deviated, horizontal, dual).
- ✓ With a gas lift system the energy source is located on surface. Subsurface components are easily / cheaply replaced using wireline (exception being sub-sea wells).
- ✓ In light of the waste reduction drive, compression facilities and gas treatment will generally be available in areas where associated gas volumes are significant. (e.g. to re-inject or export)
- ✓ Operating costs are generally low and a direct function of fuel costs and system reliability / integrity.

Cons

- ✗ Investment may be capital intensive due to compression costs, but may be reduced by adopting a central distribution plant, and benefitting from "required" compression (sales, re-injection).
- ✗ Limited drawdown capability - many deep wells cannot be lifted to abandonment.
- ✗ Lift gas is not always readily available.
- ✗ Gas lift may cause emulsions and viscous crude which are difficult to lift efficiently.
- ✗ Safety precautions must be taken for high pressure gas distribution lines and live "annuli".
- ✗ Gas lift may exacerbate gas freezing, and therefore hydrate or wax problems.
- ✗ Additional casing integrity is required.
- ✗ A total system design approach is essential. With other lift systems this is less important.
- ✗ Annulus gas inventory offshore may require annular sub surface safety systems on platform wells.
- ✗ Gas lift can be very inefficient without good surveillance practices (i.e. gas lift does not 'fail' in the same obvious manner as an ESP or beam pump), and therefore requires close monitoring to operate efficiently on a continuous basis.

1.4. Gas Lift Systems

The design of any artificial lift method should not be undertaken in isolation of the rest of the production system. This is particularly true of gas lift. Escalating development costs, both operating and capital, together with the need to conserve associated and non-associated gas dictate the need for an integrated, total systems approach to gas lift design. When analysing any gas lift system, it is essential that all appropriate physical processes are mapped out and integrated. This will lead to a consistent approach to enhance system design by matching reservoir and well performance against various process scenarios [ref. 6].

This section examines the main factors to be considered when designing/evaluating a closed rotative gas lift system. Design recommendations are provided where appropriate. Relevant design sensitivities are also discussed.

For convenience the 'integrated system' is made up of three main component parts: the reservoir, the well and the surface facilities.

1.4.1. Main Gas Lift System Design Considerations

Many factors must be considered in gas lift system design in order to match system performance to reservoir deliverability. The pullout in Chapter 4 presents an overview of the steps to be considered in the design of an integrated gas lift system. It is important that the designer has a thorough understanding of the different physical processes involved, and how they interact. See figure 1.3. below.

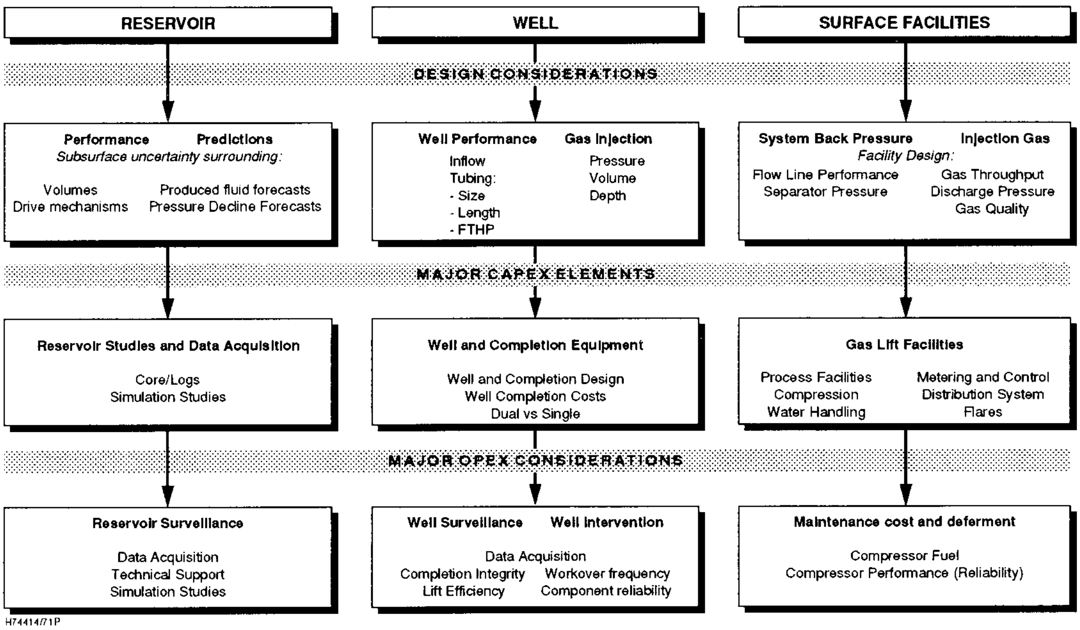


Figure 1.3. - Main technical and economic considerations surrounding gas lift systems.

1.4.2. Reservoir Performance

Drive Mechanisms and Fluid Properties

Reservoir performance (drive mechanism, PI behaviour and fluid properties), usually represent the largest uncertainty associated with artificial lift design. Such parameters will change with time, hence reliable forecasts are required to assess the effect on artificial lift performance/selection, particularly the **timing** of installation [ref. 3]. To cater for this uncertainty, systems can be designed to accommodate a range of operating conditions - with an obvious economic penalty. This emphasises the need for timely data collection.

In a number of fields, it is often the case that artificial lift is required some years into the field development. Delayed installation not only limits initial capital expenditure, but also enables better designs and decisions to be made as a result of having some production history. One advantage of gas lift in this case is that the downhole equipment can be installed with the original completion at very minor additional cost - obviating the need for a later workover.

Associated Gas Production

The quantity of associated gas produced in the wellbore is a function of a number of factors (drawdown, bubble point pressure and natural gas liquid ratio), and is a significant parameter in gas lift system design. The determination of the amount of free gas likely to be produced is crucial to determine the flowing-pressure gradient which is directly related to the optimum injection volume (Section 2.1).

As previously stated, gas lift offers a wide range of operational flexibility. A gas lift system can be employed throughout the life of a field, regardless of drive mechanism and changing fluid composition. The same, however, cannot be said for comparative pumping techniques with low gas tolerance. With current technology, it is unlikely that one pumping system could take advantage of early production potential, and still operate efficiently after rapid production decline and gas breakthrough. Under these circumstances a combination of lift methods is often considered.

In projects where there is doubt concerning reservoir performance the versatility and flexibility of gas lift is an important selection criterion that should not be overlooked.

Injection Depth

The lift gas depth is limited in principle by the available or design lift gas pressure. This is further discussed in Section 2.1.

1.4.3. Well Performance: Inflow and Vertical Lift Performance

Inflow

In high PI wells, where small changes in drawdown have a large effect on production, significant gains can be realised by maximising lift gas injection depth, the converse is also true however for low PI wells. The natural deterioration of inflow performance with time should always be considered in the initial design, particularly in areas where intervention costs are high. Depending on the forecasted pressure decline (or onset of water production), the gas lift string should be designed to cater for a range of operating conditions. Where large uncertainty exists, bracketing of mandrels should be considered. Pessimistic 'worst case' or compromise designs should be avoided, as this will generally result in unnecessarily complicated and sub-optimal completions. (See Chapter 4.)

Significant effort should be expended on determining the well inflow prior to gas lift installation, in an attempt to reduce the uncertainty [ref. 3].

Vertical Lift Performance

Tubing size is very important in gas lift design in order to operate at the maximum stable rate. Too small a tubing will result in excessive friction losses. However, too large a tubing will cause unstable flow and heading, particularly if well productivity begins to decline. This can only be corrected (partially) by increased volumes of lift gas. To assist in optimising tubing design the appropriate two phase vertical flow correlations together with good quality fluid property PVT data, must be used.

An increase in water cut may result in a reduction in PI due to relative permeability affects. This will also increase the density of the produced fluid, and simultaneously reduce the gas-liquid ratio to the detriment of vertical lift. To assess the long term completion requirements the effect of water breakthrough and PI reduction should be taken into account during initial design. (Using the long term forecast for wells.)

Low wellhead back-pressure is also of prime importance, as it allows increased drawdown and enhances the efficiency of gas lift, and hence productivity. Higher back-pressure also results in closer valve spacing and shallower injection. It is strongly recommended that gas lift systems are operated with minimum back pressure at the wellhead. See section 1.4.5 below.

Emulsions

Emulsions are common in gas lift operations, and can result in a significant increase in produced fluid viscosity with adverse effects on lift performance. Available evidence suggests that emulsions are formed at the point of gas injection.

Emulsion behaviour and its effect on well productivity can vary greatly from well to well, even in the same field, as the result of varying water cut and flow pattern in the well. Emulsions can often be successfully eliminated, or at least significantly reduced, by adding de-emulsifiers to the lift gas stream (as is undertaken in, for example, Gabon and BSP). Accurate sampling and data gathering is essential [ref. 3].

1.4.4. Well Design Considerations

There are several important aspects of gas lift which have a direct influence on well/casing design:

- The size of the production casing will be selected in line with the desired well potential, and on the physical size of the required downhole equipment (gas lift mandrels, SSSV). The production casing must be large enough to accommodate the intended completion - particularly when reviewing the feasibility of multiple tubing strings.

- The well and completion should be configured to facilitate through-tubing operations. Wireline tools will be used to maintain the well and monitor production performance (e.g. Flowing Gradient Survey).
- There are a number of gas lift operating conditions that can result in the pressure in the production casing being evacuated to atmosphere (as a result of human intervention, a surface leak or equipment failure), therefore the collapse rating of the production casing, and the design of the primary cementation, should be carefully considered during the design phase.
- It should also be noted that during initial kick off operations the production casing can be exposed to full gas lift pressure on top of a full column of completion fluid. The production casing and tubing should therefore be designed accordingly.

1.4.5. Surface Facility Considerations

The importance of minimal back pressure to conserve system energy is well documented [refs. 1, 4]. Production can be increased, and lift power decreased, by minimising facility back pressure on the well. Long and/or small-ID flowlines, production chokes, "empty" bean boxes and high separator pressures can all result in significant production bottlenecks, and should therefore be avoided.

Lift gas volume and pressure are two extremely important considerations (related to gas lift string design and compressor selection) which play a role in gas lift system design:

- **Gas lift volume** - is the total lift gas requirement for the field or group of wells determined by adding individual well requirements. It is possible to inject too much gas into an individual well. Production will increase as a function of lift gas volume until a point of maximum production is reached (the technical optimum). The addition of further quantities of gas beyond this point will decrease productivity as a result of the dominance of friction pressure. This is especially true where long flowlines are installed. Determining the shape of the lift gas performance curve is a critical step in new ventures where compression capacity is being estimated or in existing fields where gas availability is constrained (see section 4). The gas lift performance curve is also important when optimising the allocation of lift gas (see Chapter 7). Sub-optimal gas allocation is known to contribute significantly to the 'locked up' potential in a number of existing gas lift developments.
- **Gas lift pressure** - is a critical design parameter in gas lift system design. It has a major impact on completion design (number of valves), well performance (injection depth), system operating pressure (compressor discharge), and obviously material and equipment specification - all of which will have a significant impact on costs. Selection of a gas lift pressure that is too high can result in needless investment in compression and other equipment, whereas pressures that are too low can cause loss of production potential and production deferment [ref. 7]

The potential benefits of higher injection pressures are:

✓ Higher production rates due to increased pressure drawdown as a result of being able to inject deeper.

✓ In general, if lifting takes place as deep as possible, less gas volume is required. From a power point of view therefore it is more efficient to inject deep with a lower injection gas liquid ratio (IGLR), than to inject shallow with a high IGLR. In fact a number of authors [refs. 4, 7] state that "*the injection pressure that results in the lowest compression horsepower per volume of fluid lifted will generally provide the most economical producing conditions and most efficient gas lift operation*".

✓ Less downhole equipment (mandrels, valves) leading to increased reliability and reduced intervention. Equipment performance is a key consideration in an environment where intervention costs are high (e.g. subsea well, remote platform).

The obvious disadvantage associated with high injection pressure is the need for more costly, high integrity, high pressure rated, equipment (Table 1.1.).

ANSI CLASS	Pressure Rating @ 38°C	
	psi	kPa
600	1440	9900
900	2160	14900
1500	3600	24800

*Note total facility costs increase proportionally with increasing pressure rating

Table 1.1. - Pressure rating of equipment

In many instances the relative advantages of high pressure gas lift systems far outweigh those resulting from low pressure systems. Engineers are therefore encouraged to consider the merits of higher injection pressures. It should also be borne in mind, however, that in a number of cases gas compression will be installed in any case to facilitate gas export or re-injection. In these cases, the choice of lift pressure may be determined by other requirements.

1.4.6. Quality of Lift Gas

The successful operation of a gas lift system depends on a reliable source of high pressure lift gas. When evaluating the feasibility of gas lift installations, a number of important lift gas characteristics should therefore be reviewed:

- A rich (heavy) gas provides higher downhole pressure, and therefore allows a deeper injection depth for a given surface injection pressure compared to leaner (less dense) gas. Heavier fractions (NGL), however, may go back into solution with the produced fluid. The overall result in this case is that there will be little to be gained by increasing injection depth. On the other hand, lower volumes of lighter gas at a higher injection pressure may actually require less compression horse power per unit volume of fluid produced.
- Water in a lift gas system may lead to problems with corrosion, liquid slugging and hydrates. If hydrate formation is expected in the distribution system, and/or anticipated corrosion rates are unacceptable, then gas dehydration will be necessary. Glycol contacting or other gas dehydration systems are employed to condition gas streams for gas lift applications. Such systems remove hydrocarbons and significant amounts of water from the gas system [Refer to Production Handbook Volume 7]. Free water is removed by scrubbers. In cases where dehydration is not economic, hydrates can be suppressed by chemical injection and localised heating of problematic equipment.
- As well as being potential safety hazards, gas with hydrogen sulphide (H_2S) can cause severe operational problems such as corrosion, excessive compressor maintenance and fuel contamination. In such cases lift gas can be sweetened, or the appropriate materials must be used in the gas lift system and wells - with significant incremental cost.
- The lift gas supply must also be free from solids. Lift gas must ultimately pass through very small areas in gas lift valves which can be easily plugged. Rust, salt, scale or chemical residue should be prevented from accumulating in the system. Operation of dehydration equipment should consider the consequences of carry-over of dehydration chemicals.

Clearly the quality of lift gas is an important consideration which influences both well and facility design, and will have a significant impact on overall project costs.

1.4.7. Compressor Selection

Compressor selection is dependant on many factors; required discharge pressure, capacity, machine duty, operating environment and cost. Although a detailed discussion on compressor selection is beyond the scope of this document, an awareness of basic selection criteria is considered essential.

Disparity Between Kick Off and Continuous Gas Lift Operation

The main issue with compressor selection normally results from the disparity between the discharge pressure for well kick-off, and that required for continuous operation at the deepest injection point. The difference between kick-off pressure and operating pressure in many cases is so large that a single compressor cannot operate efficiently at both conditions. Attempts have been made in a number of projects to reconcile this problem by the provision of a separate, low volume, mobile high-pressure system for kick-off - with the main distribution system rated to the lower operating pressure. Experience however, has shown that this does not offer a cost effective solution, as the practicalities of operating such a system far outweigh any CAPEX savings made during the construction phase. The use of portable kick-off compressors, or separate high pressure kick-off lines, are discouraged. There will of course be exceptions.

Compressor Sizing

To calculate compressor duty, the IGLR (injection gas liquid ratio) required for each well as a function of well life and operating conditions should be estimated. Peak well requirements can then be forecast in order to determine lift gas volume requirements. Contingency factors of 10-15% are normally used or spare capacity provided by a 'stand-by' machine.

The selected gas injection pressure at the well head will determine the compressor discharge pressure. The separator pressure will, in turn, determine the compressor suction pressure. Compressor duty can then be estimated as follows:

$$\text{Power (kW) / stage} = \frac{c}{E} \times \frac{1}{m} \times Q \times T_s \times z_a \left[\left(\frac{p_d}{p_s} \right)^m - 1 \right]$$

Where:

			SI units	Field units
c	=	Conversion constant	-	-
E	=	efficiency factor (fraction)	-	-
Q	=	lift gas volume	m^3(st)/d	MMscf/d
Ts	=	absolute suction temperature	K	°R
za	=	average compressibility factor	-	-
	=	$(z_s+z_d)/2$	-	-
z_s	=	z at suction conditions	-	-
z_d	=	z at discharge conditions	-	-
p_d/p_s	=	compression ratio (absolute pressures)	-	-
m	=	0.25/k	-	-
k	=	specific heat ratio of the gas	-	-
	=	c_p/c_v	-	-

For many lift gases, k has a value of 1.25 to 1.27

***Note: 1HP = 0.746 kW**

From the above it can be seen that power requirements increase in direct proportion to increasing gas throughput, and less so with increasing compression ratio, due to the fractional exponent m. (For example, if k= 1.25 then m = 0.2). Thus, from a power point of view, it is generally more efficient to inject as deep as possible (high pressure) with a lower injection gas liquid ratio (IGLR) than to inject shallow (low pressure) with a higher IGLR, to obtain the same production rate.

Types of Compressor

- **Centrifugal Compressors** - are generally the preferred machine for most duties. They offer compactness, simplicity and ease of maintenance. Depending on specific operating conditions availability's up to 99% are possible. Reduced flexibility, and minimum flow limitations (10000 ft^3/hr) must however be recognised.
- **Reciprocating Compressors** - are the most widely used compressor in E&P operations. It should be noted that this type of machine is suitable for a wide range of application, and capable of very high compression ratios. These compressors are however limited to relatively low flow rates. Throughput can be increased by connecting cylinders in parallel. Reciprocating machines are flexible in operation and capable of tolerating wide variations in operating conditions. Initial investment is comparatively less than centrifugal machines.

An operating envelope for centrifugal and reciprocating compressors indicating capacity and pressure limitations is presented below in Figure 1.4.

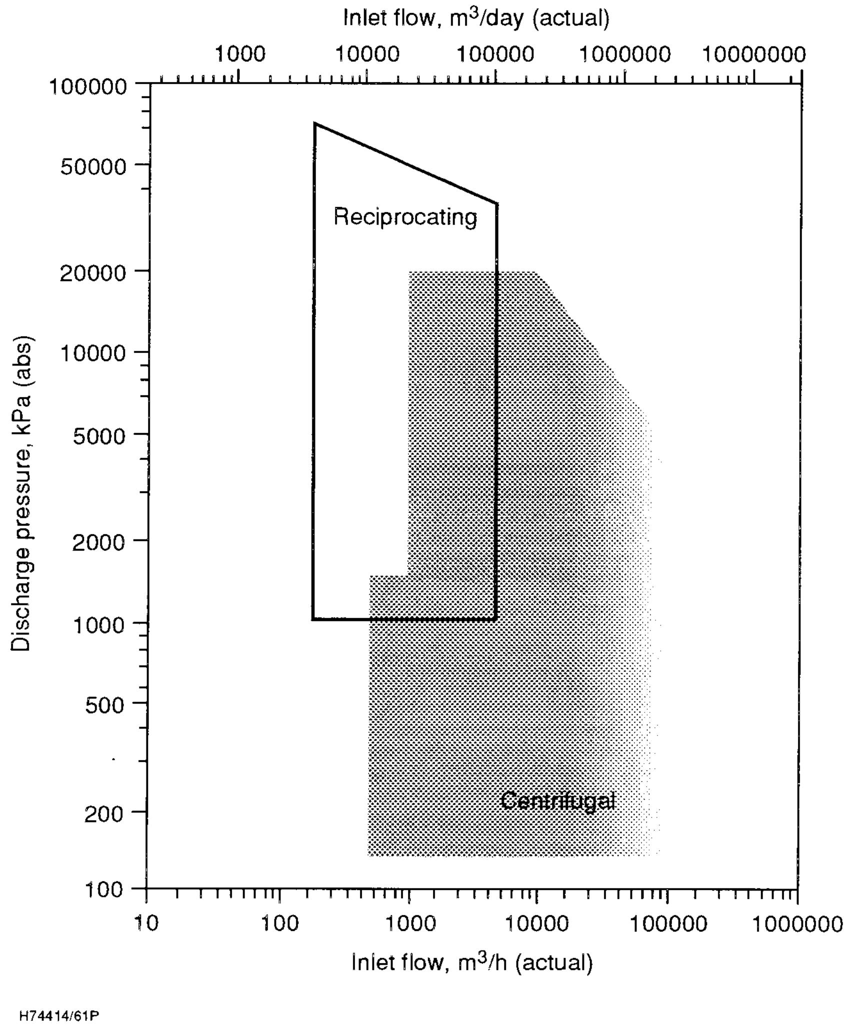


Figure 1.4. - Compressor operating envelope.

In cases where the operating condition falls into the transition zone, a more detailed study should be carried out to investigate field-life operational requirements and equipment sensitivity to future operating conditions. Detailed compressor specification and selection is the responsibility of the Rotating Equipment engineer in consultation with the appropriate vendors. For more detailed information consult references [refs. 7,8,9]. Methods for estimating the cost of compressors and compression facilities to an accuracy of ±25% are presented in the SIPM Cost Engineering Manual [ref. 11].

2. APPLICABILITY OF GAS LIFT

There are two basic forms of gas lift shown schematically in figure 2.1. These are:

- **Continuous Lift.** The continuous injection of relative high pressure gas to reduce the flow gradient.
- **Intermittent Lift.** Injection of gas below an accumulated liquid slug in a relatively short time period to lift the slug to surface.

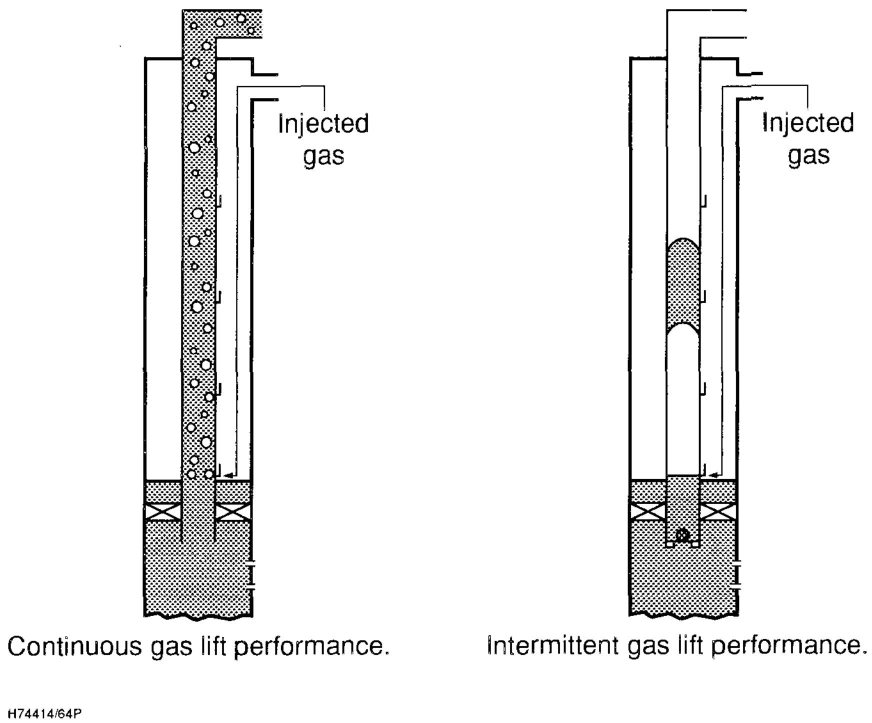


Figure 2.1. - Continuous and Intermittent lift.

This chapter provides an overview of the applicability, relative merits and design aspects of both methods.

2.1. Continuous Gas Lift

In general, optimum lift conditions are achieved when gas is injected at the bottom of the production conduit. In this way the entire vertical fluid column is less dense, which yields the lowest possible flowing bottom-hole pressure, and therefore the maximum drawdown and production rate. (See figure 2.2.)

An increased IGLR decreases the weight component of the fluid column, but the resulting higher fluid velocity also increases the friction component - thus decreasing the overall benefit. The increase in friction component is always proportional to the total conduit length (of importance in deviated wells), whereas the reduction in column weight is a function of the vertical distance. Obviously in wells with horizontal sections, the benefit of continuous gas lift is limited to the non-horizontal part of the well and in wells with long/small (near horizontal) flowlines the benefits of gas lift can be reduced.

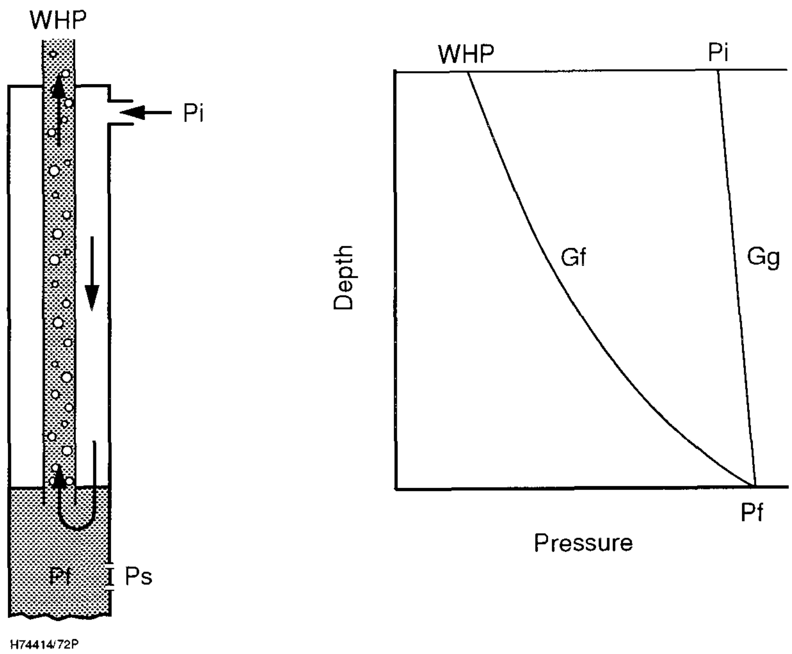


Figure 2.2. - The effect of gas injection on flowing gradient.

To determine the possible flow rates obtainable with continuous gas lift, it is necessary to determine the 'Inflow Performance Relationship' (IPR) of the well - and compare it with the *minimum intake pressure curves* for the selected production conduit when gas-lifted. This is done in the same way as for a flowing well (See Appendix A).

2.1.1. Lift Gas Volume Requirements

As lift gas volume is increased there will come a point where the benefits derived from a less dense fluid column will be outweighed by friction effects - both in the tubing, and the flow line. Increasing lift gas rates further will have little benefit on well production, and if the lift rate is increased too far then the well will begin to produce less fluid.

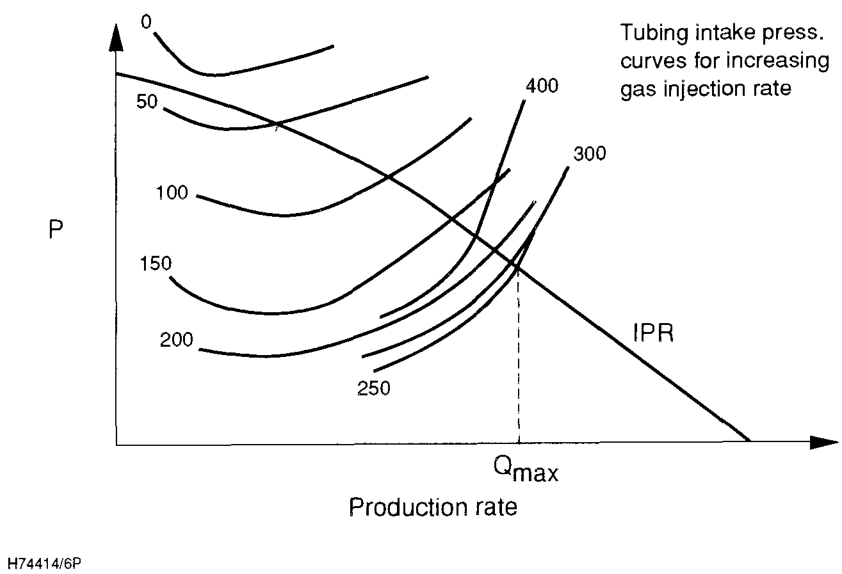


Figure 2.3. - Estimating optimum gas lift rate.

This can be illustrated by comparing the inflow performance curve with tubing intake pressure curves at various gas injection rates shown in figure 2.3. With increasing lift gas rate, the IPC's are

seen to plot lower on the P vs. Q diagram until a maximum rate is established. Further increases in lift gas rate cause the IPC's to first overlay and then begin to plot higher in the P vs. Q diagram - illustrating that the optimum gas lift rate has been exceeded.

If the intercepts of the IPC and IPR curve are now plotted as a function of well production rate vs. lift gas injection rate, the **gas lift well performance curve** can be drawn as shown in figure 2.4.

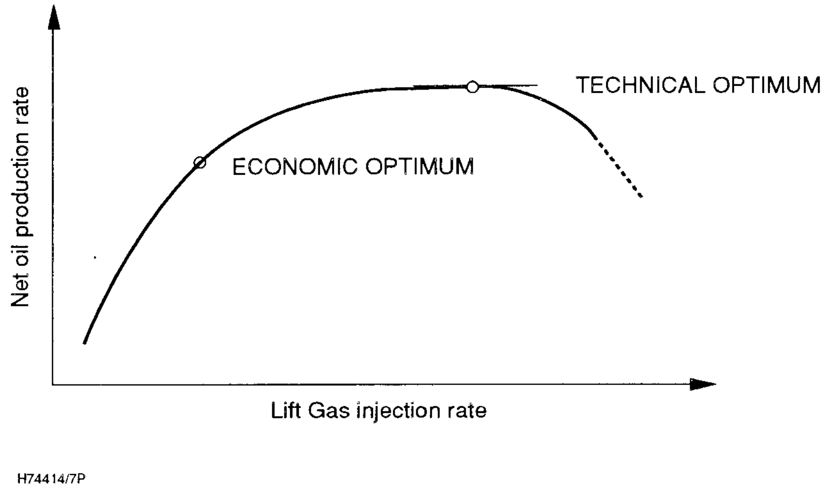


Figure 2.4. - Gas lift well performance curve.

The shape of the above curve illustrates clearly the response of the well to increased lift gas volumes. This curve is fundamental to gas lift design and operation, and will be discussed further in sections 5 and 7.

The curve has a very characteristic shape showing the benefits of increased lift gas on productivity at the lower gas lift rates, and also illustrates the phenomena of "over injecting" where little or no benefit is derived from increased lift volumes, which in extreme cases may even lead to a reduction in well productivity.

Note that any increased gas flow in the flowline will only increase the back pressure on the well, and it is therefore important to take account of the flowline response (preferably an integral part of any computer model) when establishing the optimum gas lift rate.

In practice, gas lift design will be based on the establishment of an economic optimum lift gas rate, which will be based on many factors. This represents the point at which the incremental revenue gained by increased lift rates will be offset by the cost of the supply of the incremental gas volume. Intuitively it can be seen that this volume will be less than the technical optimum value. This is further discussed in section 7.

In a brown field site, or where the capacity of compression has been established in advance, the available gas injection volume can be located on the gas lift well performance curve. This will give some indication of the possible constraint being placed on well potential, due to a lack of lift gas.

2.1.2. Injection Gas Pressure Requirements

The **operating** gas injection pressure required at the well head can be calculated from the minimum tubing intake pressure found in figure 2.3. by:

1. Subtracting the weight component of the gas column.
2. Adding the pressure loss due to friction in the gas conduit, (usually small).
3. Adding the pressure drop across the operating valve or orifice.

The pressure in the tubing which is used for the calculation is the anticipated pressure defined by the intersection of the appropriate tubing intake pressure curve with the IPR. Since gas injection at

bottom normally takes place through an orifice, the pressure differential required to pass the required lift gas rate (usually in the order of 100psi) should then be added.

The surface gas injection pressure required at the wellhead to achieve **kick-off** depends on the pressure profile in the well. The well may be full of kill fluid or dead oil, or it may be flowing at a rate lower than the rate obtainable with gas lift. (Figures 2.5. to 2.7.)

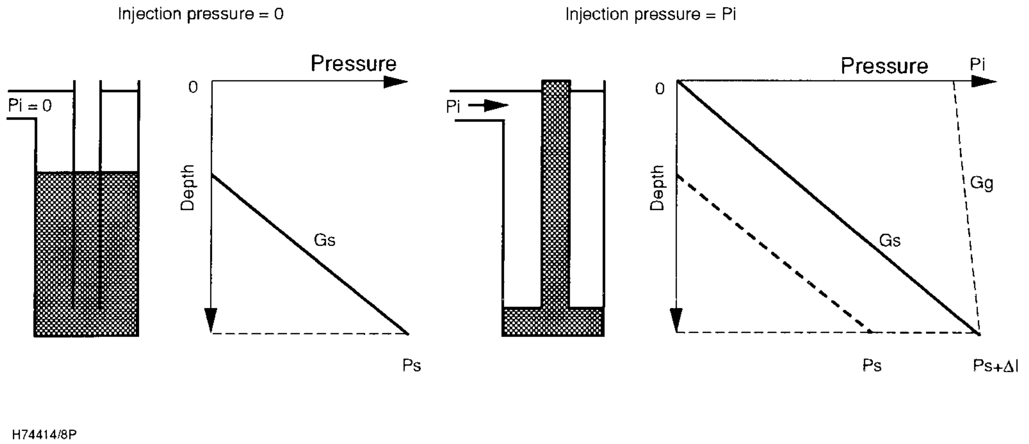


Figure 2.5. - Injection pressure kick-off requirements - well dead.

After injection of gas has been established, the flowing bottom hole pressure, and therefore the surface injection pressure required, will decrease until the minimum intake pressure corresponding to the gas lift injection rate is reached.

It can be seen from figure 2.7. that if only P_i MINIMUM is available, and if the well is either on natural flow, or full of dead fluid, no gas injection can take place at the bottom, near the reservoir.

The gas/liquid level in the annulus can only be pushed down to the depth where the pressures in the production conduit and annulus are equal. In figure 2.7., this depth is located at the intersection of the gas injection gradient with the corresponding fluid gradient. (d_1 and d_2 in the figure)

If gas is allowed to enter the production string just above this level, the GLR in the tubing will increase to a value determined by the achievable gas injection rate. The fluid pressure at the injection point will decrease accordingly and the gas/liquid level in the annulus will move down until a new pressure balance is established. It will then be possible to inject gas at this new gas/liquid level if communication is established between the annulus and the tubing. This is the function of *gas lift valves and mandrels.*

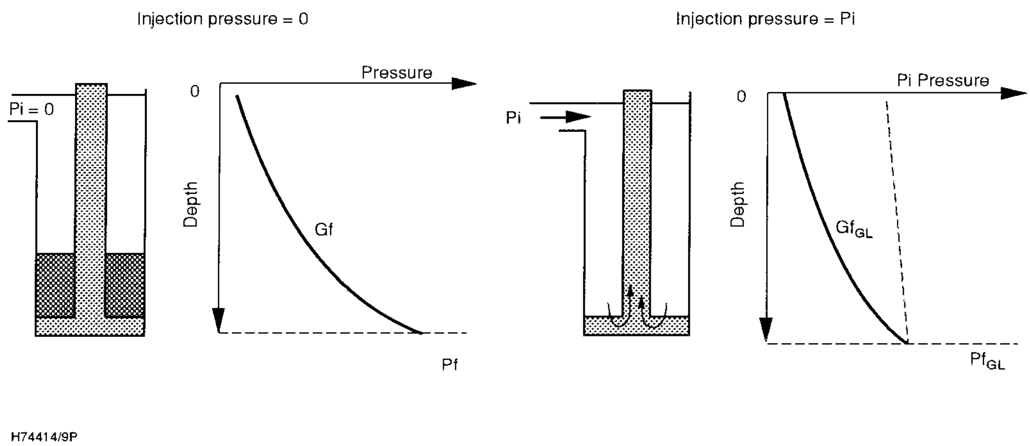


Figure 2.6. - Adding aditional gas when the well is flowing.

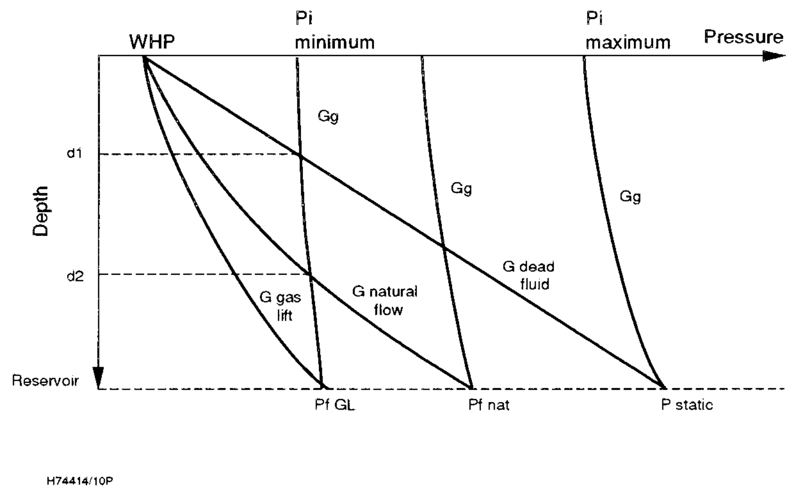


Figure 2.7. - The function of gas lift valves and mandrels.

A gas lift valve is an instrument placed in the tubing to enable communication with the annulus as and when required, opening and closing at pre-set pressures.

In a well with gas lift valves positioned at the appropriate depths, gas injection can be achieved with a lower 'kick-off' pressure than that required for a well without gas lift valves.

During the design of a gas lift string the depth of the valves, and their pressure settings, are specifically selected to ensure that the well can be *unloaded.* In other words, the fluid level in the injection conduit can be progressively lowered to enable gas injection to take place through the next deepest valve - until the maximum attainable injection depth (or the depth selected by the designer) is reached. This determines the minimum lift gas pressure required for both kick-off, and operation, of gas lift. In some cases where high pressure is already available (e.g. gas re-injection compressors), or there is a need to keep the completion string as simple as possible (e.g. subsea well), it is possible to design the well for kick-off at lift depth without any upper mandrels. However, if such a design is contemplated, the difference between kick-off and operating pressure will mean that under normal operating conditions the pressure in the gas lift system will need to be continuously choked back. This will lead to premature failure of the surface choke and downhole orifice. In addition, such a system is very energy inefficient due to the unnecessarily high pressure drops in the injection system.

Note that it is not recommended to use high pressure kick-off compressors (see Section 1.3.7.).

2.1.3. Injection Pressure Limitations

If the available surface gas injection pressure is lower than that required to enable injection at the bottom of the production string, it becomes necessary to estimate at what depth the injection point can be located (d_{max}), and what production rate ($Q_{Gas\ Lift}$) will be achieved when gas is injected at that point.

The maximum depth at which gas can be injected after the well has been kicked off (d_{max}) is a function of the:

- Surface injection pressure (P_i)
- Well head pressure (WHP)
- Natural GLR and composition of the reservoir fluid
- Gas injection rate.
- Diameter, length and inclination of the production conduit.
- Static reservoir pressure (P_s) and temperature
- Inflow performance relationship of the well (IPR)

The multi-variable relationships amongst the above mentioned parameters are calculated by a number of computer programs.

The output of these programs should provide the engineer with the best approximation of well performance presently available. This is only true if sufficient care and attention are employed to input the correct values for the various parameters and in getting a good model match with actual well performance.

Considerable work is being directed towards improving the access and user friendliness of the above mentioned programs (e.g. WePS and GLUE). The use of rougher approximations or short cuts should be avoided as the results can often be misleading.

The determination of the maximum injection depth, d_{max} and the corresponding production rate $Q_{Gas\ Lift}$ is carried out by calculating the intercept between the gas injection gradient and the 'equilibrium curve' for the well. This is dealt with in detail in Chapter 4.

2.1.4. Introduction to the Equilibrium Curve

Equilibrium curves form the basis of many gas lift calculations. Although normally generated by computer (see Section 4.1.), they can be calculated by making use of selected gradient curves. Readers are encouraged to (at least initially) be familiar with the manual construction of equilibrium curves prior to using computer tools as this will assist in enhancing the understanding of this key element in gas lift string design. A graphically-derived example of the **equilibrium curve** is given in **appendix B.**

It is helpful to visualise the situation using a pressure versus depth diagram (see Figure 2.8.). For a selected well configuration the operating wellhead pressure, and the available gas injection pressure, have been defined. The reservoir fluid properties, the reservoir pressure temperature and well IPR are also defined. With this data, pressure gradient curves can be calculated. The generalised end situation is depicted in figure 2.8.

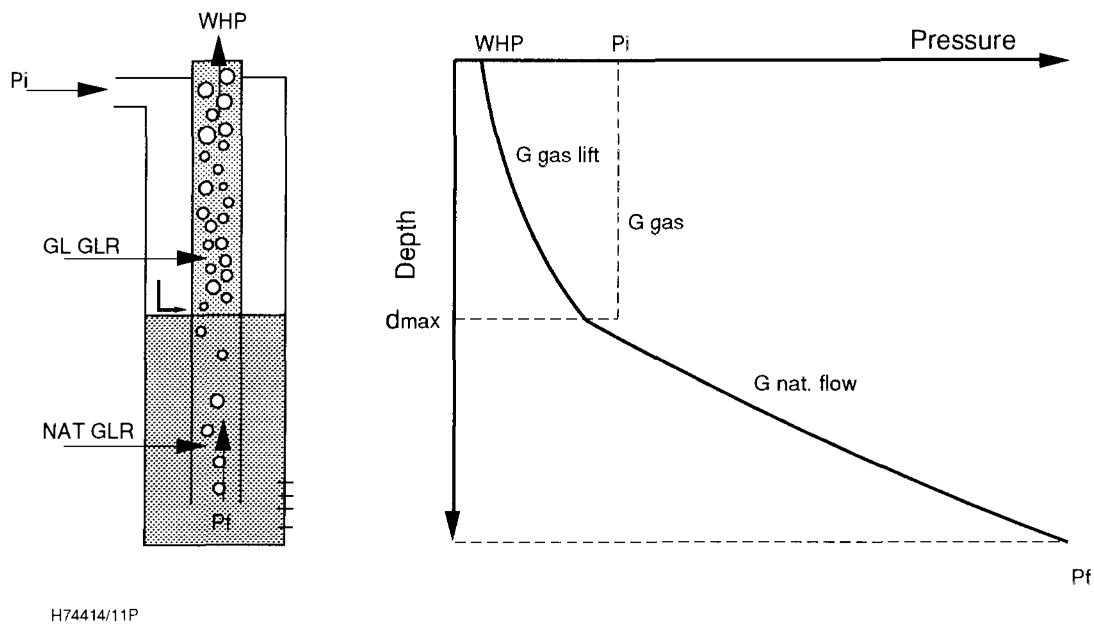


Figure 2.8. - The effect of lift gas on flowing gradient.

Two different sections can be distinguished in the production conduit of a gas lifted well:

- From the bottom to the point of gas injection; the well is flowing with the natural formation GLR.
- From the point of injection up to the surface; the well is being gas lifted, and flows with gas lift GLR.

These two sections have a common pressure point at the depth of injection. Also, although the GLR's are different, the liquid flow rate Q is the same in both sections. In the upper section, the well head pressure is defined by the surface facilities. In the lower part, the flowing bottom hole pressure is defined by the IPR. It follows that for each injection depth there is a Q (or conversely, for a given Q there is an injection depth) for which the pressure at the bottom part of the conduit on gas lift is the same as the pressure at the top of the part on natural flow. This pressure is known as the *equilibrium pressure*. Knowing the equilibrium pressures, and corresponding injection depths, for a range of flow rates enable us to determine the relationship between gas injection depth and resulting flow rate.

A curve through the equilibrium pressures for the range of depths and flow rates considered is known as the *equilibrium curve*. This curve interrelates three basic parameters for gas lift design: **depth** of gas injection, resulting production **rate**, and **pressure** in the production conduit at that depth. Since the curve is three-dimensional, it can be plotted in several ways. A practical presentation is a depth versus pressure diagram on top of a pressure versus production rate diagram with the pressure scale common to both as shown in figure 2.9.

It should be realised that an equilibrium curve is not a flowing gradient, but a representation of the attainable pressure in the tubing for any fixed total GLR under stable flow conditions, and thus forms the basis of gas lift string design. A detailed discussion on the graphical construction of equilibrium curves is presented in Appendix B, which is intended to promote a clear understanding of what the curve represents, its character and the principles behind its calculation.

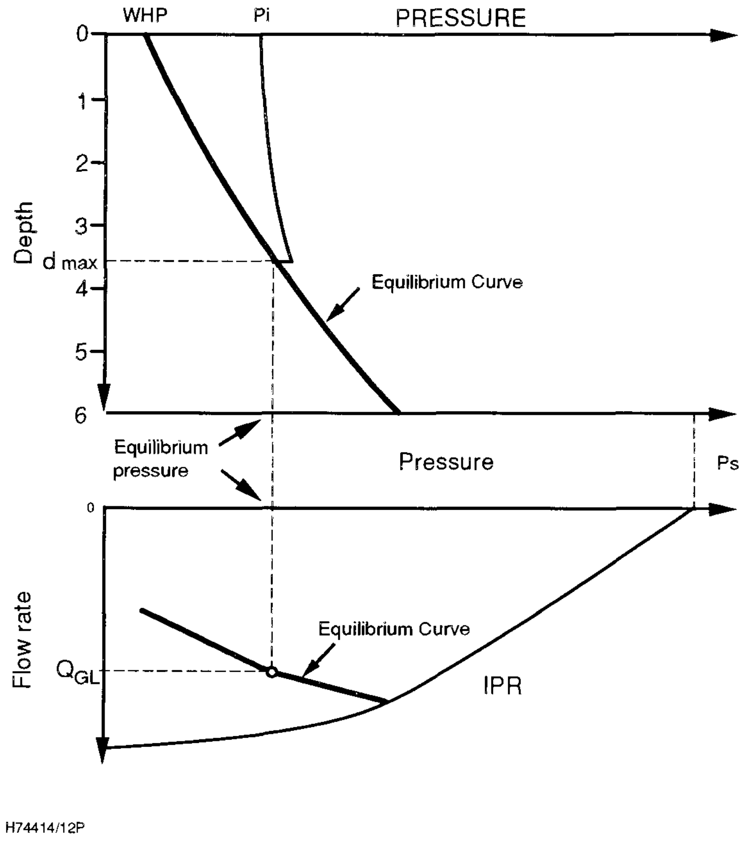


Figure 2.9. - The equilibrium curve.

2.2. Intermittent Gas Lift

Due to the limited use of intermittent gas lift within the Group a detailed discussion on design procedures has not been included in this guide. Readers considering such systems are advised to consult ref. 12 and ref. 4.

Intermittent gas lift differs from continuous lift installations in that the injection is deliberately stopped periodically to allow the build up of well fluids. During each injection cycle, a controlled amount of gas is injected below the accumulated slug of liquid in order to displace it to surface. This, in effect, enables the well to be 'pumped-off' if the wellhead pressure is bled-off during the accumulation phase. The most efficient variation of this method utilises a mechanical plunger to provide a seal at the gas-liquid interface. This is particularly effective in deviated wells.

2.2.1. Operating Sequence

The operating sequence, or cycle, after unloading an intermittent lift installation using casing operated valves is shown in figure 2.10. In (a) produced fluids rise and accumulate in the tubing. At a predetermined time (b), gas is injected into the tubing/casing annulus - increasing the casing pressure sufficiently to open the operating valve. The rest of the valves, whch are only used for unloading, should remain closed.

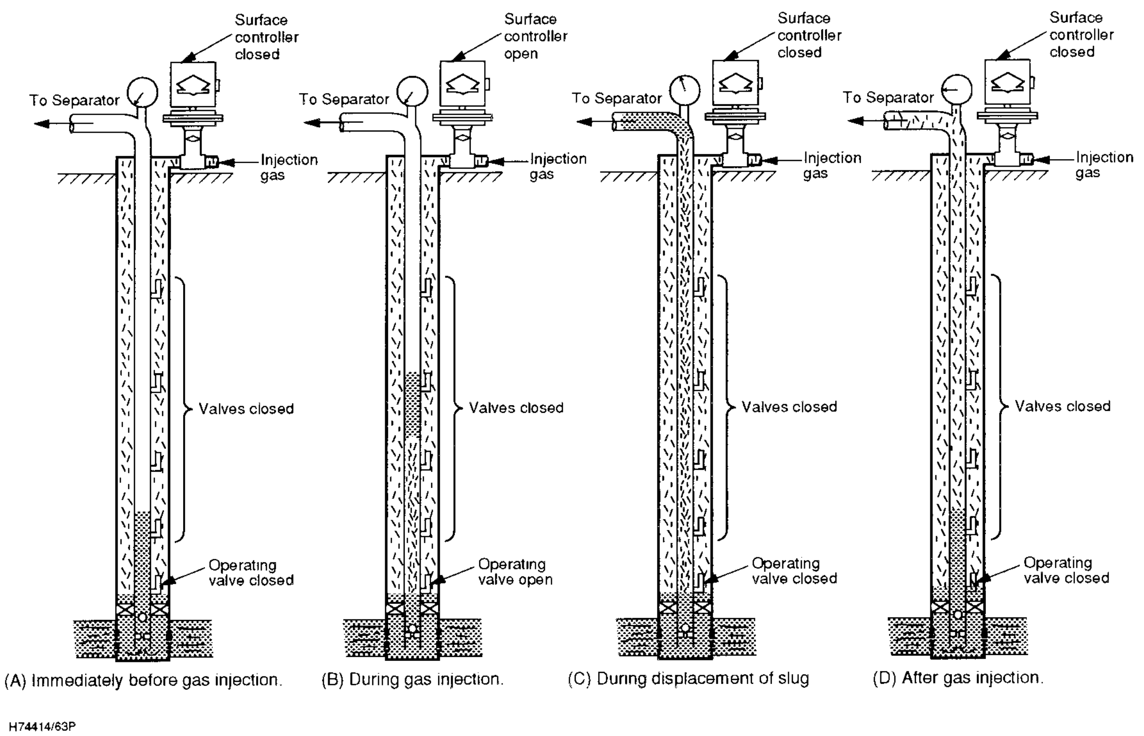


Figure 2.10. - Typical operating sequence for intermittent lift.

Gas is rapidly injected into the liquid column creating a gas bubble which expands pushing the liquid slug to surface. If a standing valve is used (as in figure 2.10.) this is now in the closed position. In (c) the slug has reached the surface at which time the operating valve has already closed. Several factors should be noted:

- Gas should be injected rapidly, if not it will tend to percolate through the liquid column. Large-ported, quick response operating valves are recommended. (e.g. pilot valves, see section 3.4.3)
- To minimise the flowing bottom hole pressure the operating valve should be located as deep as possible.

- Surface back pressure should be minimised to reduce the effect of liquid fallback and gas consumption.
- A standing valve below the operating injection depth will prevent any downward flow of fluid (or in extreme cases gas injection into the reservoir) during the gas injection cycle, and will allow production once the pressure has been bled off the tubing.
- To minimise gas usage, only sufficient high pressure gas should be injected under the slug such that when it expands it expels the slug from the well. Allowing the tubing pressure to bleed off will increase the drawdown period on the formation.

2.2.2. Intermittent Gas Lift : Applications

Intermittent gas lift is usually applied in response to declining reservoir pressure and/or poor gas lift efficiency, characterised by high Gas Utilisation Factors (see Section 7). Although usually applied to low rate wells (< 200 bbl/d), intermittent gas lift has also found application in cases where:

- Inadequate drawdown or stable production can be achieved by continuous lift.
- Paraffin deposition in the tubing presents production problems. Plungers can be used to facilitate tubing scraping.
- In cases where a gas lift infrastructure already exists, capital and operating cost can be less than other forms of lift, for example: beam and screw pumping.
- The availability of lift gas is constrained, and wells are incapable of stable flow on continuous lift at economic injection gas liquid ratios.

Within the Group intermittent gas lift applications are expected to increase by a small amount as the result of declining reservoirs and more unstable wells.

2.2.3. Design Types

Intermittent gas lift can be divided into two broad categories: **Conventional Intermittent** gas lift, and **Plunger Assisted Intermittent** gas lift. There is a third category, **Chamber Lift**, which is not covered in detail here as it is a varient on conventional intermittent lift. Chamber lift allows the volume of the slug to be maximised by utilising most of the volume in the casing. This technique used by Shell Canada finds most application in high PI, low pressure wells and is discussed in detail in reference 4.

2.2.3.1. Conventional Intermittent Gas Lift

This type of intermittent lift requires that a significant slug of fluid is produced at each cycle. The cycle frequency tends to be low. Typically 2-5 barrels/slug are produced at a cycle frequency of 1 to 3 times per hour. Inefficiency occurs due to liquid fall-back of approximately 10% of the original slug volume per 1000 feet of well depth. The liquid slug volumes, and high instantaneous production rates characteristic of this method, must be considered in the design and operation of production facilities.

Injection gas/liquid ratios (IGLR) required for this method can be generally greater than those for continuous lift installations. While the conventional method is a viable alternative for many applications, significantly better lift efficiencies in addition to other advantages can be obtained with a plunger assisted system.

2.2.3.2. Plunger Assisted Intermittent Lift [Ref. 13]

The performance of intermittent systems can be improved by use of a plunger to eliminate liquid fallback in the tubing during the injection cycle. The availability of programmable logic controllers (PLCs) and efficient plungers has led to the development of reasonably efficient systems.

The produced slug size can be low (0.25 barrels) and cycle frequency high in order to minimise the impact of slugging on production facility operations. Typical designs range from 0.25-2 barrels/slug

at 3 to 7 cycles per hour (depending on plunger 'fall-back' time). Figure 2.11. shows a schematic of a single valve Plunger Assisted intermittent lift installation.

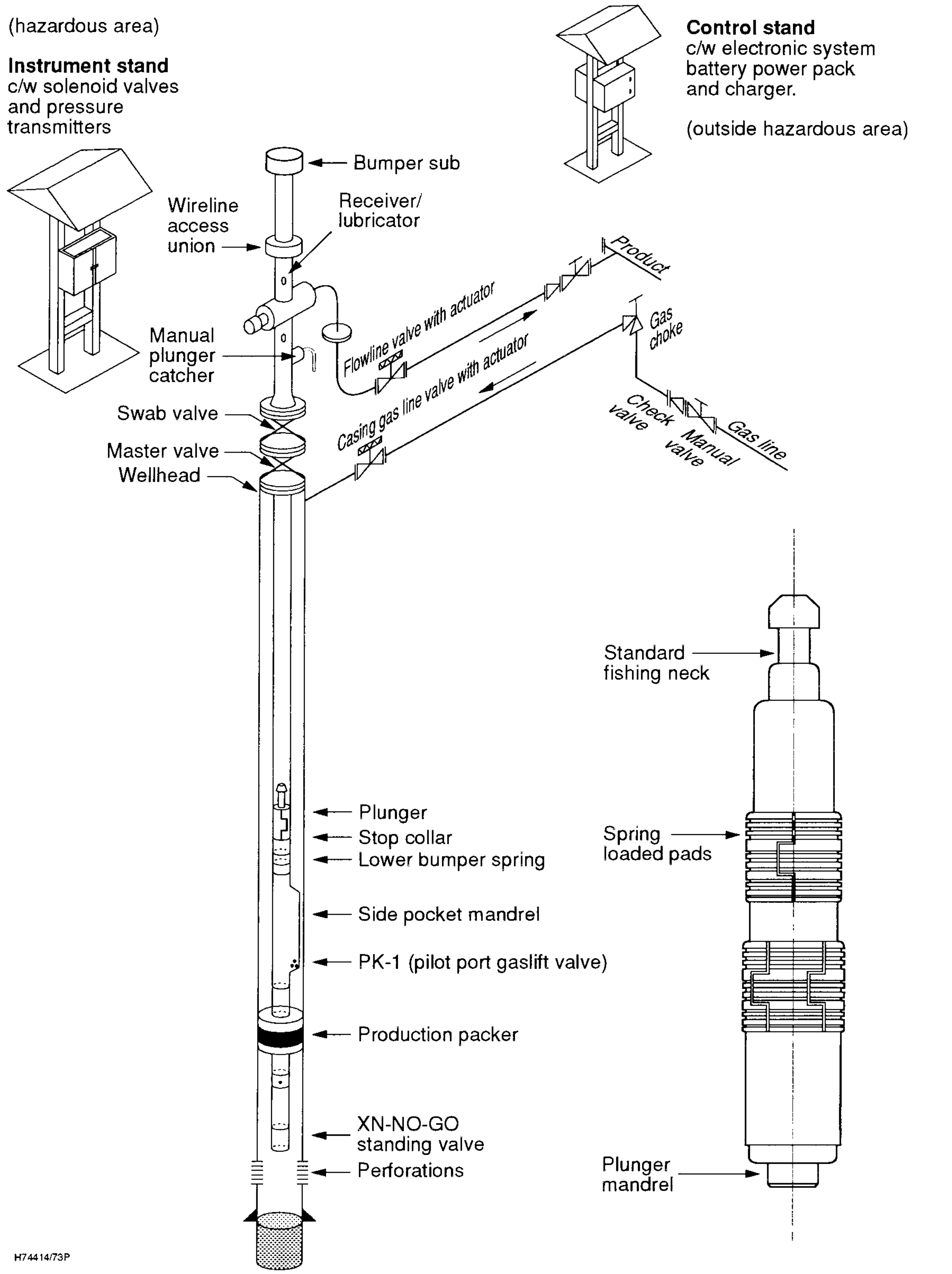


Figure 2.11. - Schematic of plunger system.

The principal components of the system are:

- *Wellhead Equipment*
  A surface lubricator which includes a shock absorber, plunger catcher and plunger sensor, is installed on top of the swab valve. The lubricator is fitted with a 'quick union' for easy wireline access.
- *Flow Line and Gas Lift Line Equipment*

  An actuated ball valve, a gas meter (usually orifice type) and an adjustable choke are included in the gas lift line. The flow line is also installed with an actuated ball valve. The actuators can be operated either pneumatically or electrically.
- *Control Equipment*
  A PLC is used to control the process cycle and safety shut-down system. A number of standard programmes are available for differing types of wells e.g. Low GOR, High GOR and packerless completions.
- *Subsurface Equipment*
  This equipment consists of a plunger, plunger stop, standing valve and intermittent type gas lift valve (usually pilot ported). All items can be wireline retrievable. Extended plungers are now available that can bypass existing mandrels. Plungers have been used in installations with full-opening subsurface safety valves.
- *Power Supply*
  The power can be either rectified mains supply, solar panels, thermoelectric generator or wind turbine. A battery back-up should be provided.

Principal advantages of plunger assisted intermittent lift systems are:

✓ Low lift gas gas requirement (approaches theoretical minimum energy required to lift fluid)

✓ Low maintenance cost compared with beam pumping

✓ Low capital cost compared with beam pump, assuming gas lift infrastructure is already in place. Cost is also independent of well depth.

✓ Maximum drawdown can be achieved

✓ Can be used to scrape wax prone wells

✓ System is environmentally acceptable (low profile, quiet)

Main disadvantages/limitations are :

✗ Requires gas lift infrastructure.

✗ Plunger may become stuck in waxy/sand prone wells.

✗ Cycle time (and hence production rate) is limited by plunger 'fall back' time. This limits the system to production rates of less than 500 BPD in a $2^7/_8$" inch tubing.

✗ Needs special extended plunger to provide 'seal' while passing any existing upper mandrels.

✗ More mechanically complex than conventional intermittent lift.

3. GAS LIFT VALVES

This section serves as a basic introduction to the design, operation and selection of gas lift valves. For more detailed information the gas lift design engineer should always check with the latest catalogues and information from the manufacturers. [Ref. 15]. In order to develop a successful design, the gas lift design engineer must have a good appreciation for the main characteristics of unloading valves.

3.1. Introduction to Gas Lift Valves

The maximum benefit from a given gas injection rate is realised when the injection takes place as deeply as possible in the string. As previously illustrated (figure 2.7), there are many cases where the maximum depth of injection cannot be reached due to limited surface pressure. For example, if a well is dead or on natural flow, the gas/liquid level in the annulus can only be depressed to the point where the pressures in the production and injection conduits are in balance.

To reach the maximum injection depth whilst minimising injection pressure, it is necessary to 'unload' the conduit by injecting gas at increasingly deeper 'ports', and to have a means to open or close these ports as required. Gas lift valves are the tools that have been developed for that purpose, and are essentially designed to open or close depending on the magnitude of the pressure in the gas injection conduit, the pressure in the production conduit, or a combination of both. Figure 3.1. shows a schematic of a typical injection pressure operated gas lift valve.

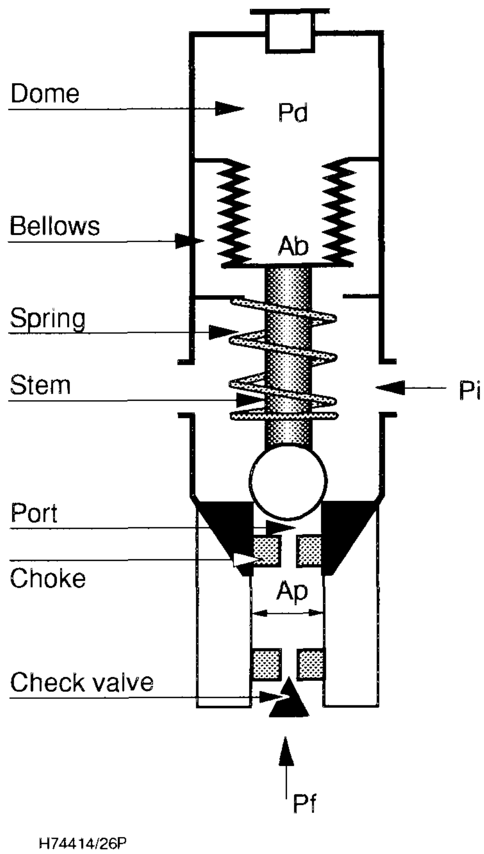


Figure 3.1. - Schematic of a typical injection pressure operated gas lift valve.

There are many types of gas lift valves on the market. Some are designed for use in continuous gas lift, some for intermittent lift. Both types are manufactured for either tubing flow or annular flow. The closing force in some valves is generated by nitrogen pressure enclosed in a chamber within the

valve. In others, a spring provides the closing force. A third type uses a combination of spring and nitrogen charge to provide the closing force.

A more recent (and on-going) development, initiated by KSEPL, is a design of a gas lift valve that is electrically operated from the surface. Although the main objective of this work is to provide an operating valve with a variable orifice, it would be a small step to move to a new generation of valves with built in sensors to accurately detect the moment when the gas /liquid level reaches the next valve and trigger the closing signal. This would lead to higher efficiency in gas lift operations by allowing maximum utilisation of gas injection pressure and a more positive and timely valve operation together with the possibility of pressure and temperature monitoring at valve depth.

To install gas lift valves, *gas lift mandrels* are added to the production conduit at depths specified by the completion design.

Side pocket mandrels are the most common, and are used for installation of wireline retrievable valves. A diagrammatic illustration of two mandrel types is shown in figure 3.2. The mandrel on the left is by far the most common (even when production pressure operated valves are run).

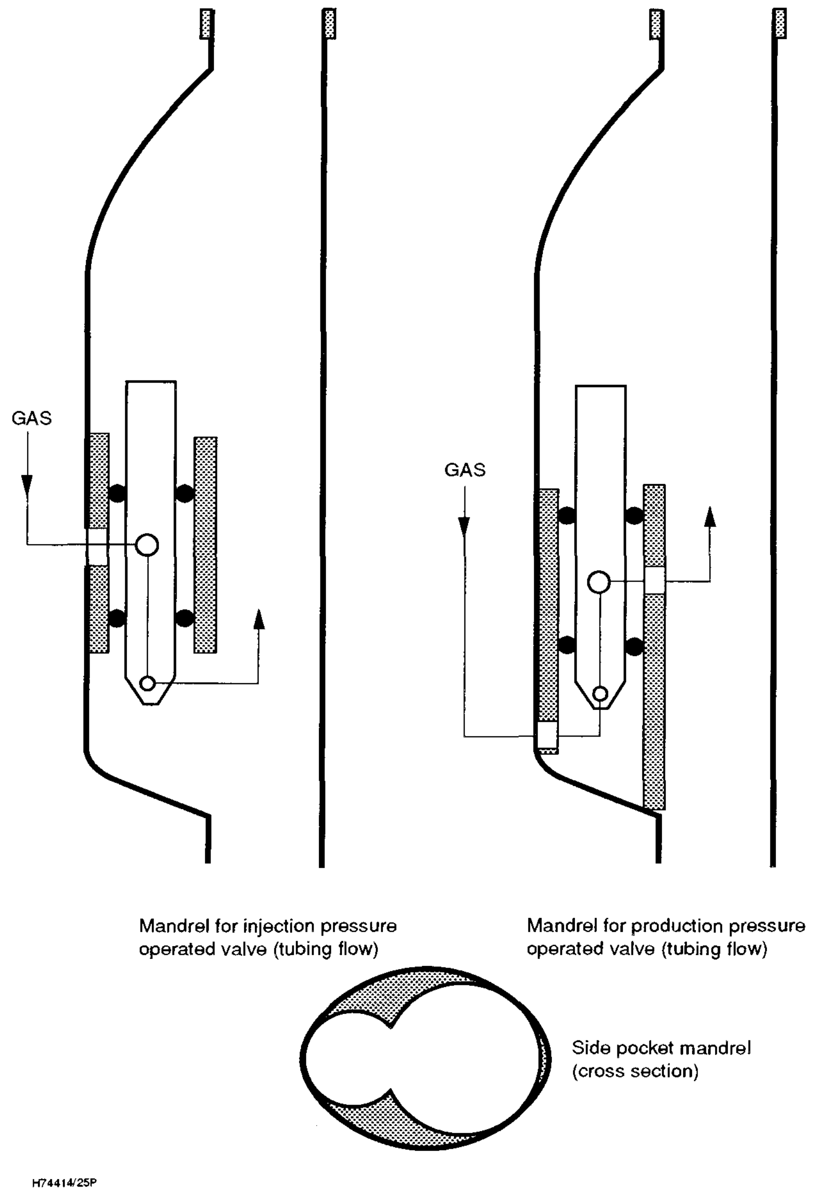


Figure 3.2. - Schematic of two side pocket mandrels.

3.2. Classification of Gas Lift Valves

In general terms gas lift valves can be classified as follows:

- Depending on which pressure provides the main opening force, valves are known as Gas Injection Pressure Operated or Fluid Pressure Operated, or alternatively using API nomenclature [ref. 14]:

Valve Type:	**GAS INJECTION PRESSURE OPERATED**	**FLUID PRESSURE OPERATED**
API nomenclature:	IPO - Injection Pressure Operated	PPO - Production Pressure Operated

Table 3.1: Classification of Gas Lift Valves

- Depending on the direction of gas flow for which they are designed, valves can be for either:

TUBING FLOW or **ANNULAR FLOW**

- Considering the type of mandrel for which the valves are designed they can be for

SIDE POCKET or **CONCENTRIC**

- Also depending of the type of mandrel for which they are intended, valves can be

RETRIEVABLE (run on wireline) or **PERMANENT** (run on tubing)

- Depending on the mechanical elements and configuration the following terms are used to further describe gas lift valves:
  - *Pressure Loaded* - Bellows, Resilient Element.
  - *Spring Loaded*
  - *Differential*
  - *Throtling*
  - *Combination*

The valve type, the valve dimensions, and the equivalent port size are important parameters which, together with the valve settings and the choke size, determine the valve performance under operating conditions. Although in practice the selection of valve type is to a large extent dependent on market availability, it is worthwhile to remember that valve characteristics may play an important role in optimising the gas lift operation. In particular, the gas lift design engineer must have a good understanding of the valve gas passage behaviour (see section 3.6.).

3.3. Type of Gas Lift Valve to be Used

The following list is not intended to be definitive, but is included to give the designer an indication of the relative merits of commonly used gas lift valves. Note that (within the Shell Group) the usage of PPO and IPO valves is split roughly 50:50.

Production Pressure Operated Valves (PPO)

Pros:

- ✓ Deeper injection achievable for a given injection pressure
- ✓ In dual completions the use of PPO's minimises string interference
- ✓ Not greatly influenced by fluctuations in casing pressure

Cons:

- ✗ Closer valve spacing is generally required
- ✗ Well Performance must be known accurately
- ✗ Generally only applicable to stable wells
- ✗ Gas throughput can be constrained and valve behaviour can be affected by small port size. Particularly for smaller valves (1" or less)
- ✗ It is often difficult to determine whether production anomalies are a result of inflow/tubing behaviour or valve malfunction

Injection Pressure Operated Valves (IPO)

Pros:

- ✓ Better gas lift control - less sensitive to well heading problems
- ✓ Suitable for high rate applications as valves can be designed for high throughput
- ✓ Fewer mandrels and valves are required
- ✓ Most commonly used valve in the industry

Cons:

- ✗ Higher injection pressure required to achieve same injection depth as a PPO valve
- ✗ Stable injection gas pressure is required

3.4. Valve Mechanics

Referring to figure 3.1, the **dome** is a chamber that can be charged to a selected pressure (P_d) - usually with nitrogen. The **bellows** connected to the dome allows expansion or contraction of the nitrogen volume, and provides a means to transmit movement to the **stem**.

The stem is fitted with a **ball** which can be pushed against its **seat** (at the top of the port) to close the flow of gas through the gas lift valve. The **spring** provides a force tending to keep the valve closed. **Choke's** of the required size are installed to regulate the maximum volume of gas passing through the valve. The check valve is designed to prevent backflow of well fluid into the valve and the injection conduit. The valve is in the open or closed position depending on the balance of forces acting on the active valve elements e.g. in an IPO valve.

- The spring, and the dome pressure acting on the bellows area (A_b), generate forces that close the valve. These forces are set during calibration.
- The gas injection pressure acting on the bellows area and the fluid pressure acting on the port area generate forces that tend to open the valve. These forces depend on the pressures in the conduits at valve depth, and are determined during the gas lift design.

3.4.1. Injection Pressure Operated Valves (IPO)

In this type of valve, the **main opening force** is generated by the **injection gas pressure** at valve depth. Figure 3.3. illustrates a typical injection pressure operated valve.

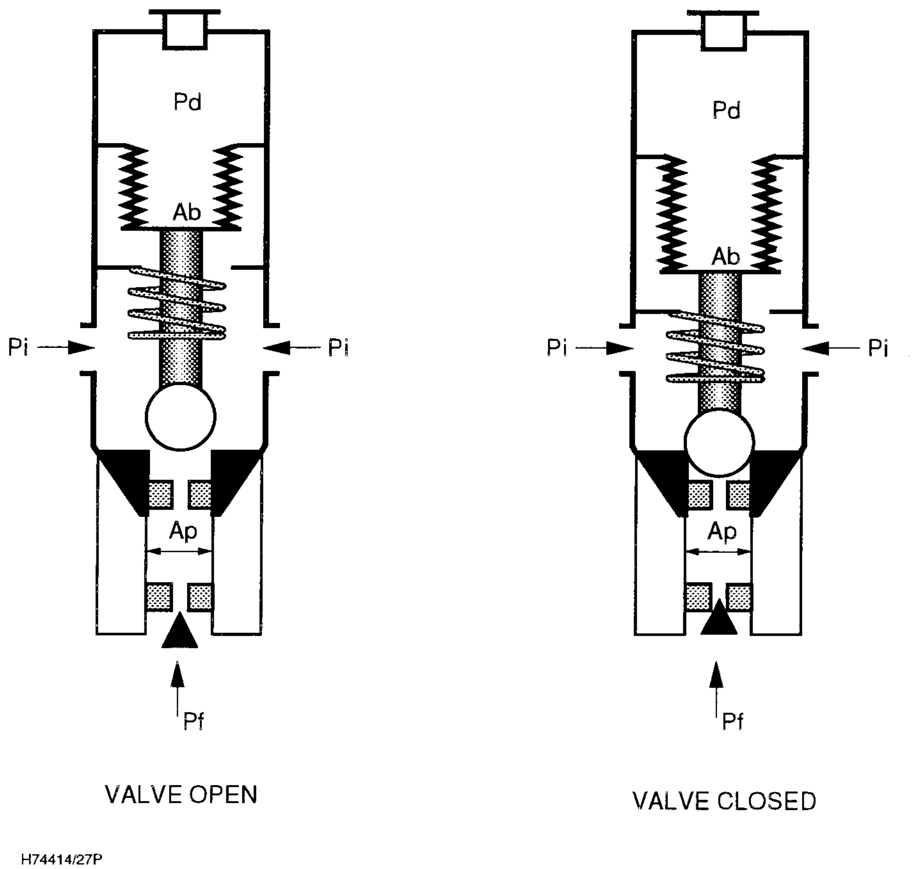


Figure 3.3. - Injection pressure operated valve (IPO).

IPO valves are closed (and kept closed) by reducing the lift gas injection pressure. This allows the valve to stay closed even if the production pressure subsequently increases.

Note that in the open position, depending on bellows load rate and choke size, the IPO valve may show some sensitivity to production pressure (Pf). This results from the fact that in a number of valves the stem does not travel sufficiently to allow the ball to completely 'clear' the port, and therefore if the production pressure is reduced the valve will begin to close.

Recent work carried out by Shell Oil [ref. 16] on an IPO valve (Daniels RP-1, a 1" valve) concluded:

"Research at the University of Tulsa indicates that neither the assumption of full casing pressure nor full tubing pressure acting on the ball area during closing is correct. The reality is a complex range of pressures which depend on the flow geometry. During several experiments the pressure below the ball seat was less than the tubing pressure, with pressure recovery occurring before the check valve (see figure 3.4). The assumption of tubing pressure acting on the ball more closely fits measured test data. Because the valve's dynamic response is dependant upon the valve's geometrical and physical properties, it can only be determined through physical (dynamic) testing."

Thus, the valve has a tendency to begin to throttle closed rather than to remain open longer and to close due to decreasing casing pressure as it is intended. In the smaller sizes of valve (1 inch or less), the ratio of port-to-bellows area tends to be greater - and therefore this throttling effect becomes more pronounced (see section 3.6.).

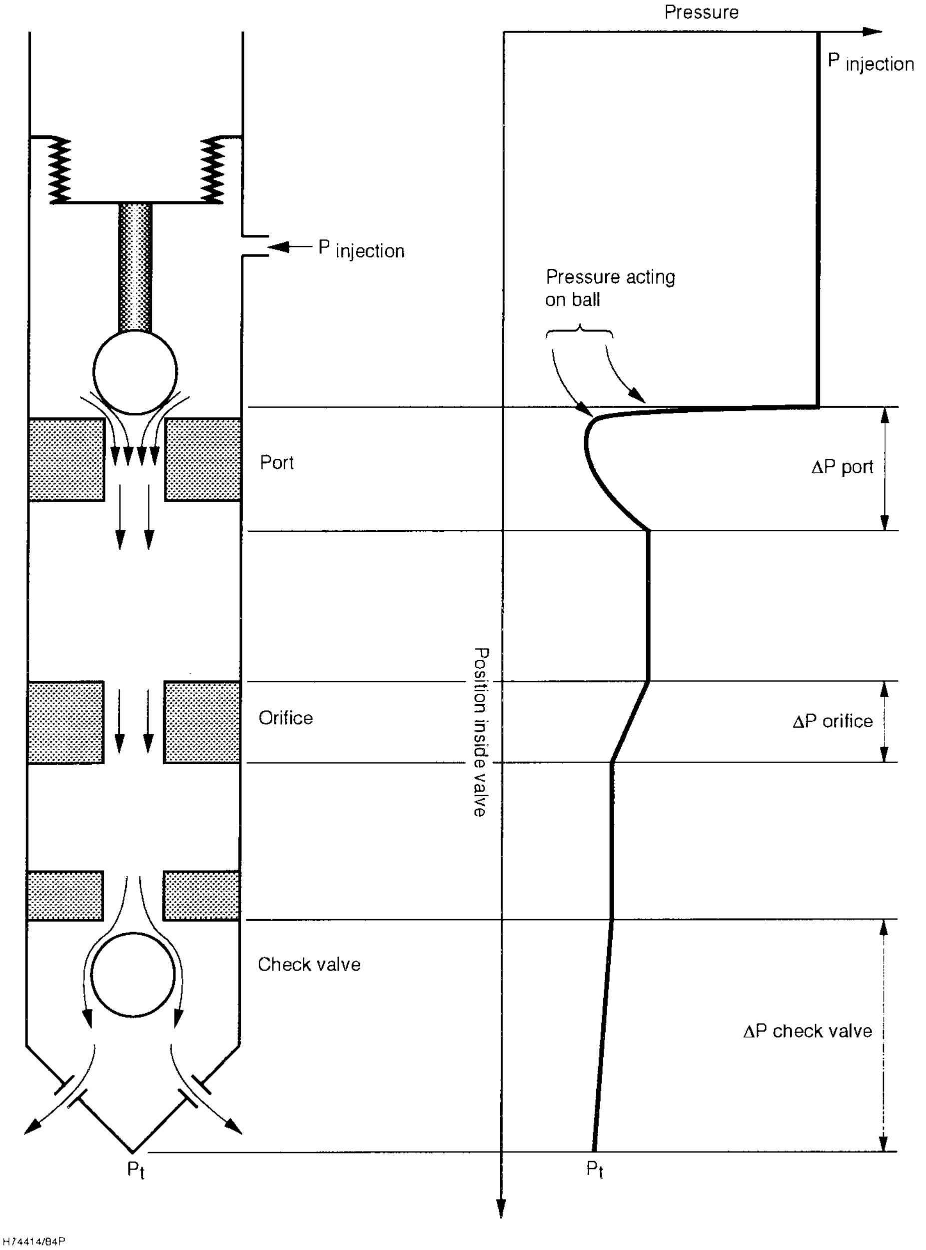


Figure 3.4. - pressure profile inside an operating IPO valve.

3.4.2. Production Pressure Operated Valves (PPO)

In this type of valve the **main opening force** is generated by the **fluid pressure** in the production conduit at valve depth. The valve illustrated in figure 3.3. can be converted to become a 'fluid operated' valve for illustration by interchanging Pi and Pf. This is illustrated in figure 3.5.

Now when the valve is closed, the gas pressure P_i acts under the stem on the port area Ap, and the fluid pressure P_f acts on the bellows minus stem area. When the valve is in the open position, the choke (and the throttling effect of the ball on the port) induces a pressure loss, and the pressure acting under the bellows and stem area is close to Pf.

The above valve requires the special mandrel shown in figure 3.2 to operate in this configuration. The most common type of PPO valve used in the Shell Group utilises a conventional mandrel. This therefore means that a bypass must be provided in the valve itself.

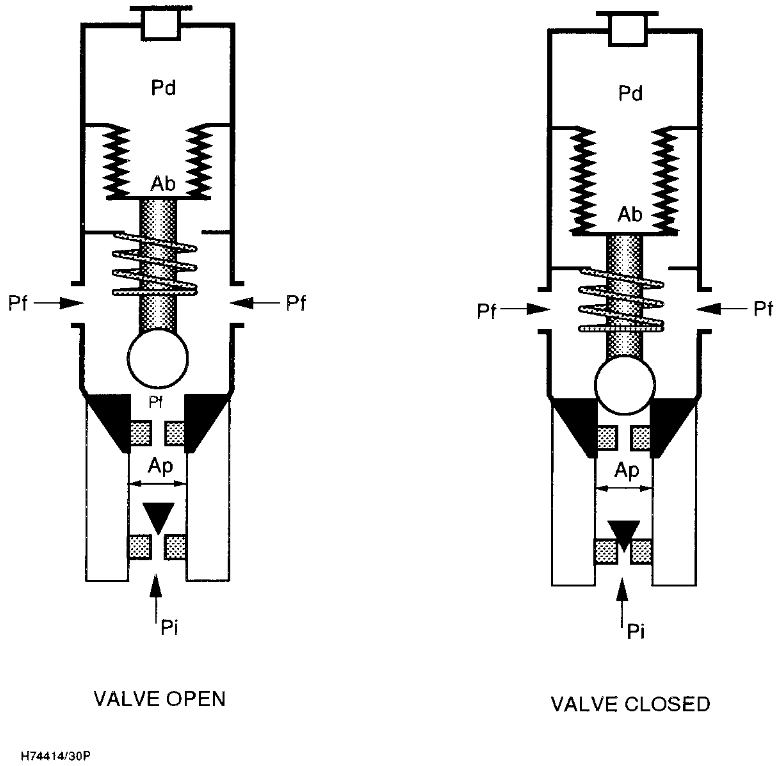


Figure 3.5. - Production pressure operated valve.

Figure 3.6. shows the configuration of the most common type of PPO currently used. The most frequently used types in the Shell Group are the 1 inch Camco BKR-5 (bellows) and BKF-6 (spring) valves.

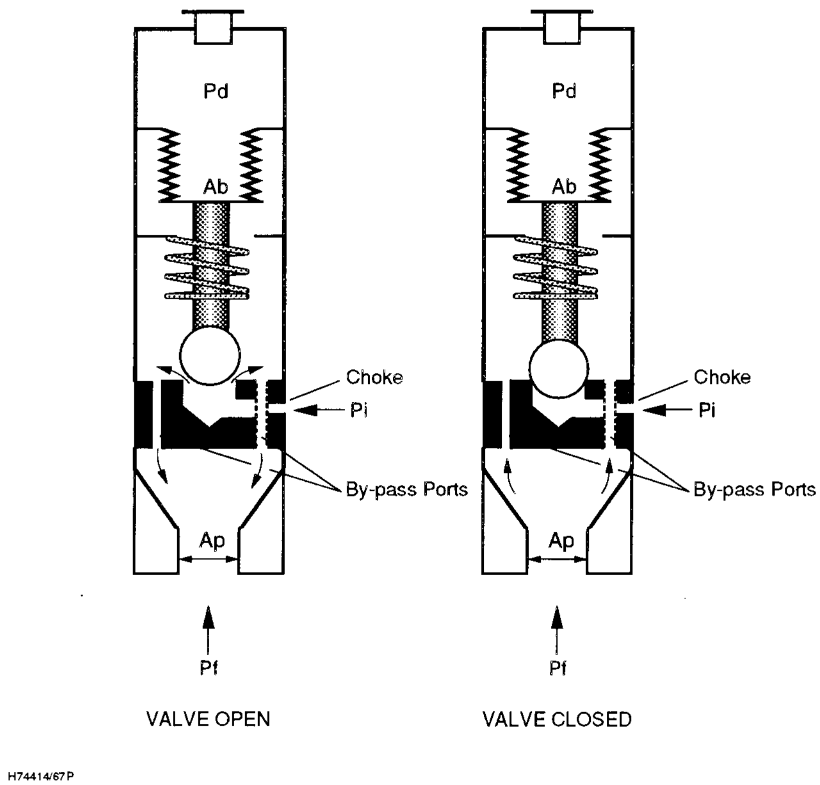


Figure 3.6. - Common PPO valve configuration.

It is important to note the effect that the geometry of these smaller valves will have on valve performance. Firstly, depending on spring or bellows load rate, the ball may not 'clear' the seat in the open position (as is the case with IPO valves) - this will cause 'throteling', or may restrict the valve passage.

Secondly, because of the requirements for bypass ports, the smaller valves have restrictions on port size - which again limits valve throughput when compared to an IPO valve. It is very important that these throughput restrictions are understood by the gas lift design engineer (see section 3.6).

3.4.3. Pilot Valves

This type of valve is operated by an increase in Pi. See figure 3.7. When the pressure in the bellows is overcome, the 'pilot' portion of the valve allows the annulus pressure to act on a piston, causing the 'power' section of the valve to move. A large volume of gas from the larger ports in the power section can now flow into the well. The valve is held open by the differential pressure between Pi and Pf. The power section is closed by a spring as Pi is reduced, and the pilot section closes in the normal manner.

Pilot valves may be required if large gas injection rates are required. These valves are often used in intermittent gas lift installations.

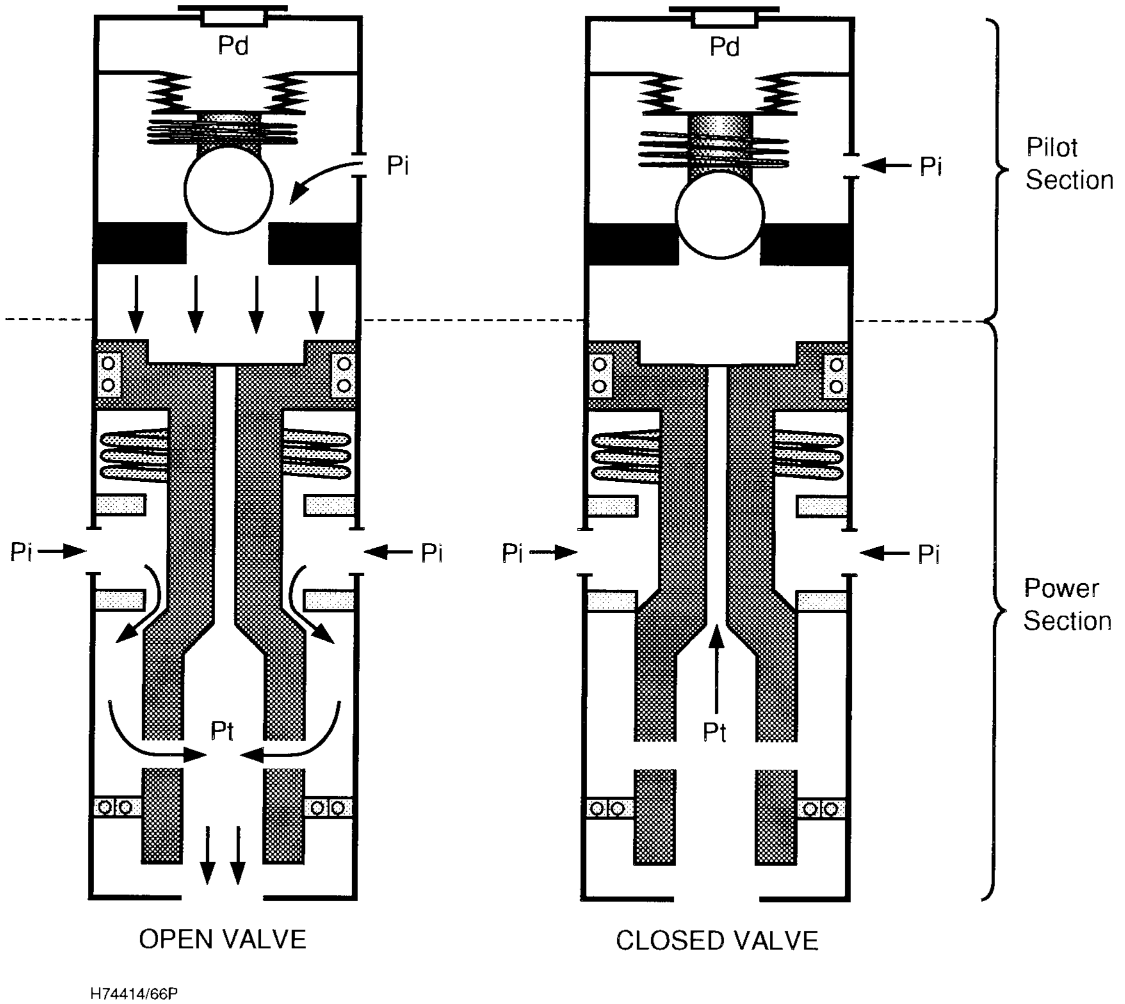


Figure 3.7. - Schematic of pilot operated valve.

3.4.4. Other Types of Gas Lift Valve

There are many models of gas lift valves designed for a range of applications (eg proportional response valves), but a detailed description of the various models is outside the scope of this manual. Such descriptions, together with relevant dimensional, mechanical and operational data, can be found in the manufacturer's catalogue.

It should be remembered that valves and combination valves are manufactured and marketed under similar (sometimes misleading) names by different suppliers, and that the differences between these valves are not necessarily very clear. Therefore, it is very important to obtain full documentation and discuss the details with the manufacturer to ensure that the valve type selected is the most suitable for a given application.

3.4.5. Gas Lift Valve Opening and Closing Equations

For each valve configuration, the opening and closing equations are determined by making a balance of the forces acting to operate the valve. From such equations the required calibration value of the closing force for each valve in the gas lift string is calculated.

At the moment of closing, or at the moment of opening, the general valve equation is:

Forces acting to open the valve = Forces acting to close the valve

The opening forces are generated by the gas injection and/or the production fluid pressures acting on the areas exposed to them. The closing forces are generated by the dome pressure and/or the spring acting on their working areas.

For convenience, the following nomenclature and definitions have been adopted:

A_b	=	bellows area		
A_p	=	port area		
A_s	=	stem area		
S	=	spring tension. (Expressed as a pressure acting on A_b - A_p)		
F_b	=	bellows factor	=	$A_b / (A_b - A_p)$
F_p	=	port factor	=	$A_p / (A_b - A_p)$
F_s	=	stem factor	=	$A_s / (A_b - A_p)$
$F_{(p-s)}$	=	port minus stem factor	=	$(A_p - A_s)/(A_b - A_p)$

In many valves $A_s = A_p$. In this case $F_b = 1 + F_p$, which leads to more compact formulae.

3.4.6. Examples of Opening and Closing Equations

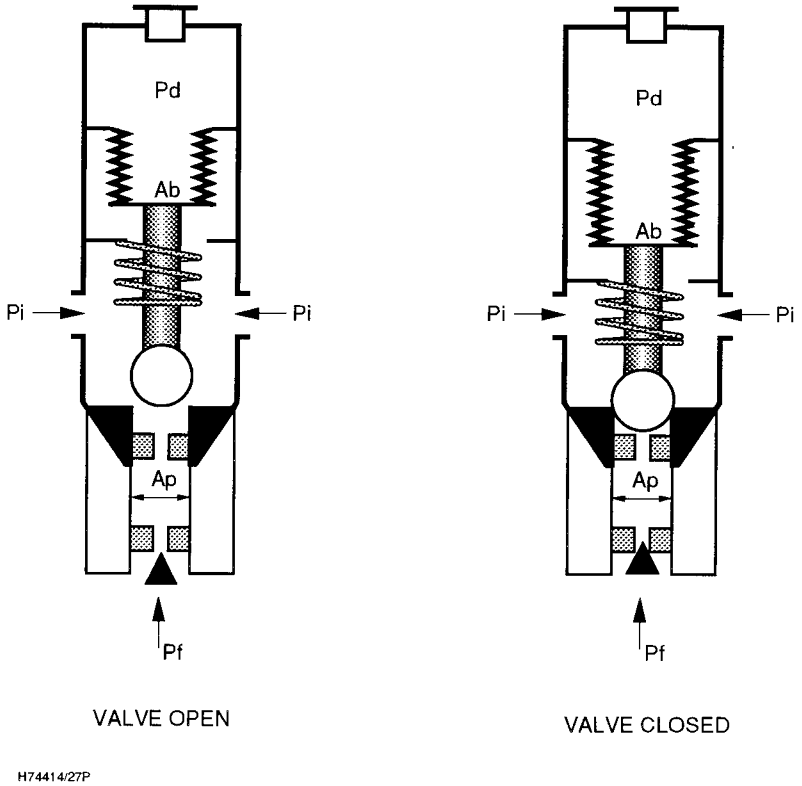


Figure 3.8. - Injection Pressure Operated Valve.

Opening and Closing Pressure of an IPO Valve

As an example the equations for the injection pressure operated valve shown below in figure 3.8 are developed.

Opening equation:

$$P_i(A_b - A_s) + P_f(A_p) = P_d A_b + S(A_b - A_p) \quad (1)$$

(if there is no spring, S=0)

Solving for P_i

$$P_i = \frac{P_d A_b + S(A_b - A_p) - P_f A_p}{A_b - A_s} \qquad (2)$$

In most cases $A_p = A_s$ and therefore the above equation is normally simplified to:

$$P_i = \frac{P_d A_b - P_f A_p + S(A_b - A_p)}{A_b - A_p}$$

$$P_i = P_d F_b - P_f F_p + S \qquad (3)$$

Idealised closing equation:

$$P_i(A_b - A_s) + P_i A_s = P_d A_b + S(A_b - A_p)$$

$$P_i A_b = P_d A_b + S(A_b - A_p) \qquad \text{or} \qquad P_i = P_d + S\left(1 - \frac{A_p}{A_b}\right) \qquad (4)$$

In other words, the valve closes when the injection pressure at valve depth is decreased below the dome pressure.

This assumes that the fluid pressure Pf does not play any role when the valve is open and gas is being injected. This would be the case given a small choke positioned downstream of the port. Since the higher injection pressure replaces production pressure under the stem, the injection pressure at which the valve closes is lower than the injection pressure required to open the valve.

The assumption that the fluid pressure Pf does not play any role when the valve is open is not always correct. As previously stated (see section 3.4.1), in many cases, depending on the valve geometry, there is a throttling effect due to the localised pressure drop under the ball when the valve is about to close. This effect is strongly influenced by the tubing pressure, and so the closing pressure will be affected by Pf. In this event, the valve will throttle-closed at a higher value of Pi than that predicted by the above equation, and will approach (or be the same as) the opening pressure. Therefore in many cases, the relationship developed in equation 4 will be invalid and the closing pressure of the valve will be closer to the opening pressure given by equation 3.

The exact closing pressure is a function of the valve's gas flow geometry (from the inlet port to the exit port), and the load rate (stiffness) of the bellows (which in turn is affected by the dome pressure). This can only be determined by physical valve testing.

While the exact closing pressure is difficult to determine, *if the injection pressure is below the idealised closing pressure given in equation 4, the valve is closed.*

The difference between the closing and opening injection pressures is **valve spread**. Spread is dependent on tubing pressure and so is not a fixed value. The closer the production pressure is to the injection pressure the lower the spread.

Lower valve spread means the well is more sensitive to pressure changes (injection and production) and may therefore be less stable in operation. The more stable situation of higher spread is gained by:

1. a greater pressure drop from injection to production (smaller chokes or ports and shallower injection)
2. smaller port to bellows ratio (i.e. larger ports).

The design for a larger port will require the use of a larger design injection pressure drop at each valve to prevent re-opening. The most stable valve therefore may be an IPO valve with a larger port than necessary and a small downstream choke included in a design with relatively large design injection pressure drops. This will of course require a higher lift gas pressure. This is the approach Shell Oil has successfully taken in many wells where this extra conservatism produces operationally stable wells but does not significantly impact production.

Gas lift stability is discussed further in section 4.7.

Opening and Closing Pressure of a PPO Valve:

The same logic applies to the opening and closing pressures of a PPO valve, with the exception that Pi acts on the port area, and Pf on the bellows, as follows:

$$P_i A_p + P_f(A_b - A_p) = P_d A_b + S(A_b - A_p) \quad (5) \quad (\text{Assuming } A_p = A_s)$$

Dividing by $(A_b - A_p)$:

$$P_f = P_d F_b - P_i F_p + S \qquad (6)$$

Closing pressure of PPO valve:

$$P_f\left(A_b - A_p\right) + P_f A_p = P_d A_b + S\left(A_b - A_p\right)$$

$$P_f A_b = P_d A_b + S\left(A_b - A_p\right)$$

$$P_f = P_d + S\left(1 - \frac{A_p}{A_b}\right) \qquad (7)$$

However, as the ball approaches the seat, the injection pressure will increase under the ball requiring a lower Pt to fully close the valve. In this case, again, the opening and closing tubing pressure will tend to be the same.

3.5. Valve Calibration

P_d is the pressure that should be present in the dome **under operating conditions** for the valve to open at the selected values of P_i, P_f and S. At the time of calibration, the temperature of the valve must be compared with the valve temperature in the well, and a temperature correction calculated and applied to the dome pressure at calibration temperature.

The temperature correction factor C_T is derived from van der Waals non-ideal gas law:

$$\frac{P_1}{Z_1 T_1} = \frac{P_2}{Z_2 T_2}$$

or:

$$P_1 = \left[\frac{Z_1 T_1}{Z_2 T_2}\right] P2$$

Where Z_2 is the compressibility factor at temperature T_2. The temperatures are in absolute degrees (Rankin = °F + 460, or Kelvin = °C +273)

If operating conditions are labelled with the subscript 2 and calibration conditions with subscript 1 and defining the temperature correction as :

$$C_T = \frac{Z_2 T_2}{Z_1 T_1}$$

The pressure to be set in the dome at the time of calibration is:

$$P_1 = \frac{P_2}{C_T}$$

In most publications the temperature correction factor is derived assuming that the valves are at 60°F (520°R) at the moment of calibration. Nitrogen is generally used to charge the dome in gaslift valves. Tables of these values should be used if available. An approximation for 60°F is $C_T = 1.0 + 0.002224(T_2 - 60)$ where T_2 is the temperature under actual operating conditions.

A more practical approach is to measure the prevailing temperature in the calibration room and calculate C_T accordingly. This minimises temperature changes when the valve is taken out of the constant temperature bath for testing and calibration.

3.5.1. Nominal Setting Pressure or Test Rack Opening Pressure

Valves are usually calibrated, or **set,** in a test rack. For pressure loaded valves it is not practical to set the actual dome pressure directly. Rather, the dome is overcharged and the pressure released gradually until the valve opens at the required external opening pressure.

Therefore all valves are calibrated in terms of an external pressure, applied at the test rack, that would open the valve if the dome pressure or/and the spring tension was set correctly. This pressure is known as the *'nominal setting pressure'* (P_n) or the *'Test rack opening pressure'* (P_{TRO}). In this text P_n will be used throughout.

The nominal setting pressure (P_n) is the external pressure at which the valve opens at a selected standard temperature, and with atmospheric pressure under the valve port.

For valves having the port area (A_p) not equal to the stem area (A_s) a special test rack is used in order to apply the nominal setting pressure (P_n) on (A_b -A_s) as well as on (A_s - A_p). As a result, P_n acts on the area (A_b - A_p), which is the same area on which the spring is deemed to act. See figure 3.9.

$$P_n(A_b - A_s) - P_n(A_p - A_s) + 0 \quad = \quad \frac{P_d}{C_T}(A_b) + S(A_b - A_p)$$

$$P_n(A_b - A_s - A_p + A_s) \quad = \quad \text{'' \quad ''}$$

$$P_n(A_b - A_p) \quad = \quad \text{'' \quad ''}$$

In general, the balance of forces at the test rack is:

$$P_n(A_b - A_p) + 0 = \left(\frac{P_d}{C_T}\right)A_b + S(A_b - A_p)$$

or

$$P_n = F_b\left(\frac{P_d}{C_T}\right) + S$$

The equation above is good for all types of valves.

For common values where Ap is equal to As, the equations resolve to these:

Unbalanced IPO Valves:

Opening pressure

$$P_i = P_n C_T + (1 - C_T)S - P_f(F_p)$$

Closing pressure

$$P_i = \frac{(P_n - S)C_T + S}{F_b}$$

Test Rack Opening (TRO)

$$P_n = \frac{P_i + P_f(F_p)}{C_T} + \left(1 - \frac{1}{C_T}\right)S$$

Unbalanced PPO Valves:

Opening pressure

$$P_f = P_n C_T + (1 - C_T)S - P_i(F_p)$$

Closing pressure

$$P_f = \frac{(P_n - S)C_T + S}{F_b}$$

Test Rack Opening (TRO)

$$P_n = \frac{(P_f F_b - S)}{C_T} + S$$

Note: That the opening pressure is lower than the closing pressure. In a PPO valve the opening pressure is the pressure at which the valve will begin to chatter open. The production pressure must exceed the closing pressure for the valve to remain open. For that reason, the closing pressure equation is used as the basis for the test rack opening equation.

For the most common types of valves used in the Shell Group,

Unbalanced IPO valves with bellows and no spring:

Opening pressure

$$P_i = P_n C_T - P_f F_p$$

Closing pressure

$$P_i = \frac{P_n C_T}{F_b}$$

Test Rack Opening (TRO)

$$P_n = \frac{P_i + P_f(F_p)}{C_T}$$

Unbalanced PPO valves with spring and no bellows pressure:

Opening pressure

$$P_f = P_n - P_i(F_p)$$

Closing pressure

$$P_f = \frac{P_n}{F_b}$$

Test Rack Opening (TRO)

$$P_n = P_f F_b$$

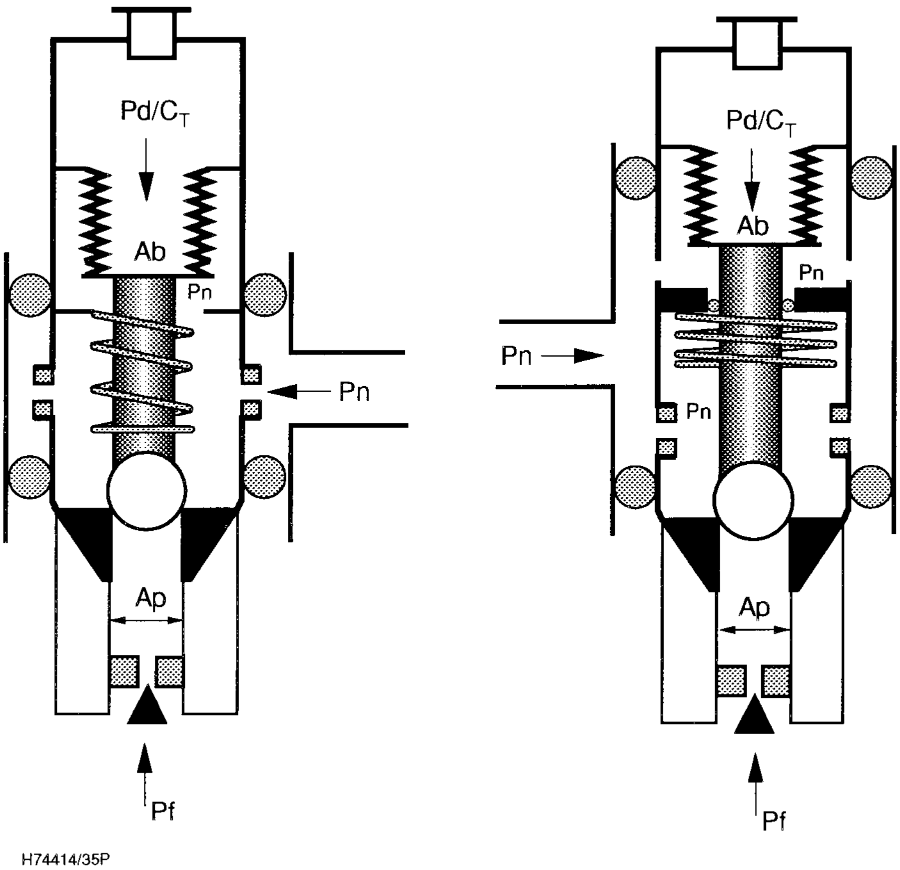


Figure 3.9. - Valves in a test rack.

Summary.

For valve calibration the following steps are followed:

1. From the gas lift design identify the values of P_i and P_f and the valve temperature at the moment the valve should close. (See Chapter 4.)
2. From the valve specifications select the appropriate port and choke size, and define the opening and closing pressure.
3. From 1 and 2 above calculate the required Pd for the valve.
4. Note the prevailing temperature in the work area used for calibration, and submerge the valve(s) in a water bath controlled at that temperature. Calculate the temperature correction factor Ct.
5. From the calibration equation; calculate the Pn at which the valve should open in the test rack.
6. Charge the dome with a higher than required Pd, and gradually bleed off this pressure until the valve starts to open when Pn is applied to the test rack. Since this handling may cause the temperature of the valve to change, submerge the valve again in the controlled temperature bath long enough to stabilise the temperature, and repeat the calibration until the valve operates at the desired pressure at calibration temperature
7. Ensure that the valve is clearly labelled (usually etched) with the well number and the intended depth at which it should be installed. It may be beneficial for surveillance purposes to label the valve with a specific date.

3.6. Gas Passage Through Valves

The determination of gas passage through a selected valve is an important part of gas lift string design, see Section 4. The main criteria for an unloading valve is that it will pass sufficient gas to unload the well to the extent that the next (lower) valve can be uncovered, and that it will close and remain closed once lift gas is injecting deeper in the tubing string.

Valve performance curves (or formulas) to quantify gas passage for a range of injection and production conduit pressure conditions are normally supplied by the manufacturers. However, only a limited number of valve configurations have been tested under simulated field conditions. Results indicate that care must be taken to obtain representative data. Work on this subject is being carried out in an industry-sponsored program at the University of Tulsa [ref. 17]. Some manufacturers have participated in the programme, and this will tend to improve the reliability of published data. In addition, Shell Oil and at least one OPCO (SPDC) have elected to carry out dynamic valve testing on their most commonly used valves [ref. 28].

The required injection gas volume is usually controlled by one (or more) orifices in the valve, and by the movement of the ball and stem. Selection of the correct orifice size is usually carried out with the help of charts supplied by the manufacturer. (This can also be done using the Windows GLUE programme.)

Most charts are based on equations for gas flow through square-edged orifices, such as the Thornhill-Craver equation. The flow of gas through a gas lift valve is not quite the same as the flow through a simple orifice, particularly when the valve is near closing, and/or the flow regime is in the non-critical region. In general gas passage through the valve will be somewhat less than that predicted by Thornhill-Craver. At the University of Tulsa, the gas passage performance of various gas lift valves has been empirically established in a specially built facility.

The results of the tests indicated that, as expected, the experimental values are not in good agreement with calculations carried out with simple orifice performance formulae. Sometimes extensive deviations were identified.

Tulsa has been working on an empirical model to enable better prediction of gas passage through gas lift valves. Initially, the model was developed for 1.5 inch OD pressure operated valves. This has been the subject of several SPE papers and presentations at various meetings. Work recently done by Shell Oil has shown some shortcomings in this work, and therefore the results should be used with care.

Some manufacturers supply gas lift valve performance data for their valves. This service must be actively encouraged.

As the valve performance test programme in Tulsa and similar institutions continues, data for more valve types and sizes should become available.

Schematic examples of the shape of the performance curves for various gas lift valve configurations are shown in figure 3.10.

Note that IPO valves tend to have a large throttling range. In addition, the same valve will exhibit quite different behaviour as the test-rack pressure is increased. This causes the load rate (stiffness) of the bellows to change, and in turn affects stem movement. It can therefore be seen that the gas passage of this valve will be significantly affected by the bellows pressure.

The gas lift design engineer must verify that the valve selected can pass the required amount of gas at the given downhole design conditions, otherwise the well will not unload.

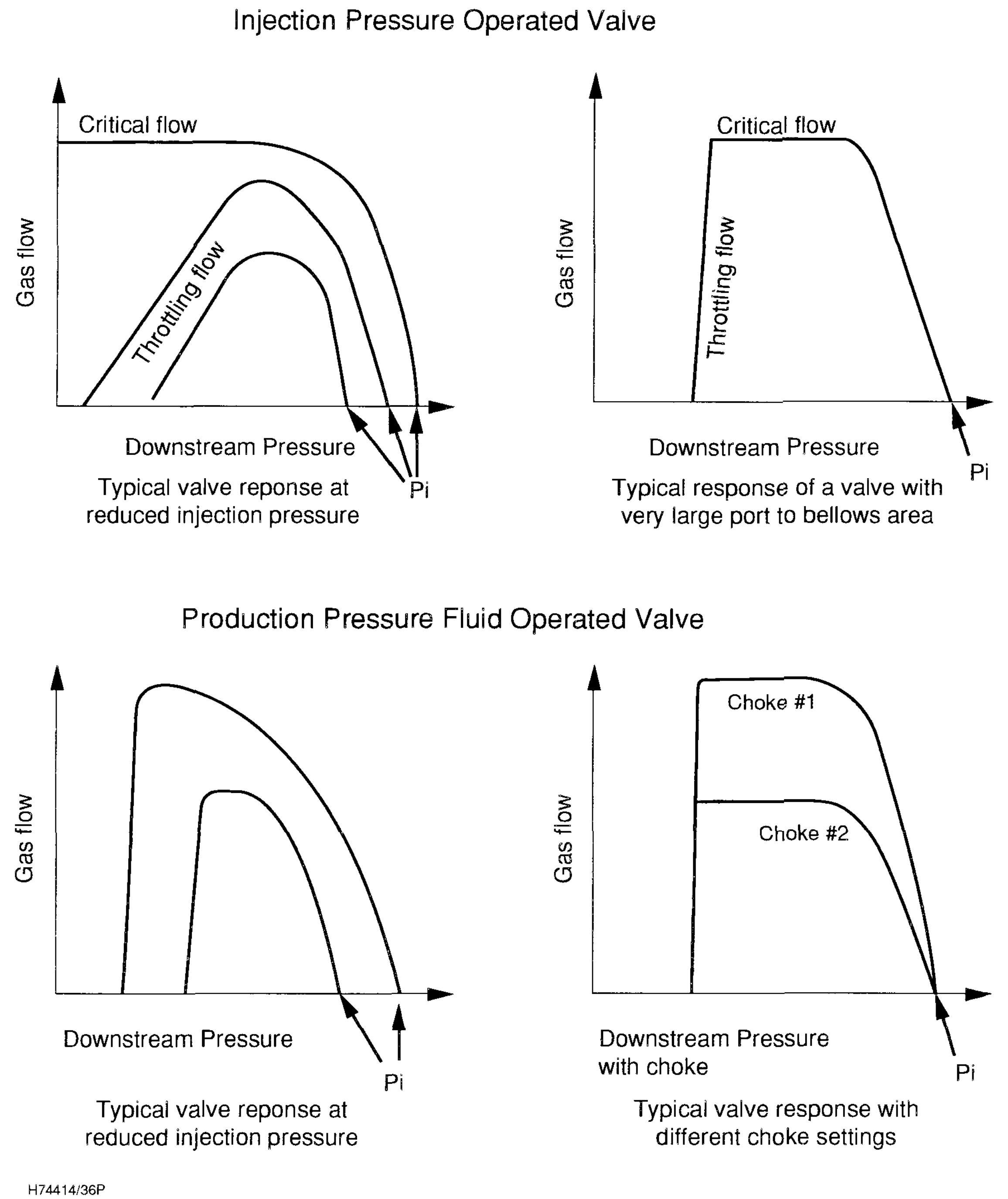


Figure 3.10. - Schematic shapes of performance curves for different types of gas lift valves.

PPO valves tend to show little or no throttling, as the pressure drop over the ball and seat only increases the influence of Pf (see figure 3.5). Again, the ability of the valve to pass gas will depend to some extent on the bellows or spring load rate.

In cases where a large volume of gas passage is required, care should be taken when sizing the orifice used in these valves. If the pressure drop through the bypass ports becomes excessive, this will cause the valve to be dominated by the casing pressure and therefore it may not close at the design tubing pressure.

Once again it is important to verify that the chosen valve will pass the designed gas rate to enable unloading to the next (lower) valve.

4. GAS LIFT DESIGN

The purpose of this chapter is to outline the basic steps required when designing a gas lift system. The main emphasis has been placed on well design, with section 4.2 and appendix B covering gas lift string design in detail. A separate section (section 4.7) has been included on well stability, which should be a fundamental consideration in any gas lift design. The "tricky" subject of dual gas lift design is addressed separately in section 5.

4.1. The Process of Gas Lift Design with SIPM Supported Computer Tools

This section is intended to give an overview of the **process** of gas lift design and should serve as a "road map" to gas lift system design in general.

The design of any gas lift system is an iterative process incorporating a number of "feedback" loops. Two pull out flow charts have been prepared (see figure 4.23 and 4.24), and continuous reference will be made to these figures throughout this section.

Reference will also be made to SIPM supported computer design software.

4.1.1. SIPM Supported Design Tools

The current SIPM supported computer tools which are used for gas lift design are WePS - Well Performance Simulator (part of PEGASUS) and GLUE - Gas Lift Users Environment (to be introduced in 1994, and available initially as a PC WINDOWS package). These tools are complimentary, each covering different aspects of the business. Although it contains some "operational" features, the strength of WePS lies in the area of conceptual planning - whereas GLUE is intended as a diagnostic, detailed design, redesign and lift gas allocation tool. It is planned to migrate the design and analysis functionality in GLUE to WePS in 1995/96, in order to provide full gas lift design capability on the same platform.

It should also be mentioned here that GLUE is intended for use as a production optimisation tool in conjunction with CAO (Computer Assisted Operations) and a number of features in the current release of this programme are geared towards analysis of producing wells. (See Section 7.4.)

The procedures in the following sections are intended to give an outline guide to gas lift design illustrating where WePS and GLUE play a role. Since the software tools are presently undergoing rapid development, it is not the intention to give a detailed description on how to run the software. This information can be found in the user manuals for the programmes.

4.1.2. Third Party Software

Recently, a considerable number of gas lift design programs (six, at time of writing) have become available from 3rd party software suppliers, and have found use around the Group. In cases where 3rd party software offers missing functionality, it will be considered for incorporation as part of the artificial lift suite of programmes in PEGASUS (e.g. as is the case with SubPump, the ESP design/ selection programme, MDS for beam pumps and PC Pump for progressive cavity pumps.)

One area of missing functionality in the current suite of programmes is complete system modelling (networks with/without process modelling etc.). The question of whether a fully integrated system model is justified, or the degree to which the modelling takes place (i.e. full process simulation, reservoir simulation etc.), will depend on the complexity of the facilities and the purpose for which the model is being constructed (Conceptual design, System Design or Production Management). Various "fit for purpose" model configurations may therefore be required, and it is considered unlikely (or perhaps even undesirable in the interests of simplicity) that one model be used for all purposes. In many cases a "simple" model may provide and adequate solution. This issue goes well

beyond the subject of gas lift design and is currently receiving attention both in SIPM and in several OPCOs.

4.2. Basic Principals of Gas Lift Feasibility, Design and Operation

The main steps in gas lift design and operation are:

1. Characterisation of reservoir behaviour, and collection of gas lift design data.
2. Gas Lift Feasibility study (and comparison with other methods).
3. Conceptual well and facility design.
4. Gas lift system and detailed well design.
5. Production Management and Optimisation.

The process involved in steps 1 to 3 (principally field development planning) are illustrated by the flow chart shown in figure 4.23. Step 4 (detailed design) is illustrated by the flowchart shown in figure 4.24. Step 5 is covered in chapter 7.

4.2.1. Reservoir Behaviour and Gas Lift Design Data.

This phase of the design is concerned with the collection of the relevant data to enable an outline study to be carried out. Type of reservoir, an assessment of the reservoir drive mechanism and the hydrocarbon fluid properties (together with surface location data) will already give some indication of the various lift options. Data collection, and the types of data to be collected, are outlined in refs. 3 and 14. Even at this early stage, some assumptions will have been made regarding reservoir/well performance to arrive at a reserves and reservoir forecast. It may be necessary to re-visit some of these assumptions later when the design has been firmed up. The use of computer tools at this stage is confined to reservoir modelling and conceptual well performance modelling using WePS.

4.2.2. Gas Lift Feasibility Study.

This step considers the viability of gas lift in the proposed development, and allows a comparison with other lift methods. This stage is characterised by the question "*what will gas lift do for me?*" i.e. what impact will gas lift have on the overall field forecast and ultimate recovery.

Typically, the questions to be answered here are:

- What tubing/flowline size should be assumed?
- What effect does increasing lift gas injection rate have on well productivity and that of the field?

The emphasis is on targeting for the **technical optimum.** It is assumed (unless other constraints have been identified) that gas lift will take place close to the top of the shallowest reservoir.

4.2.3. Conceptual Well and Facilities Design.

The purpose of the conceptual gas lift design is to focus in on the basic design parameters such as:

- Well design (e.g. completion type, tubing size, depth of lift etc.).
- System requirements (e.g. lift pressure and volume, flowline/separator sizing etc.).

At the end of this stage, sufficient information should be available to make a reasonable cost estimate for the facility and begin detailed design.

There is considerable interaction between the elements of conceptual design (system requirements and well design) - making it a highly iterative procedure (see figure 4.23). Where a certain constraint is known or fixed in advance (e.g. lift gas pressure, lift depth, available gas volume), as is sometimes the case in a "brown" field site, then this constraint is used as a starting point for the design. As part

of the design process, the constraint itself should eventually be challenged in the context of increased production potential, or increased efficiency of the lift system.

The main steps involved in conceptual gas lift design are outlined below.

4.2.3.a. Inflow/Outflow and Feasibility

When no constraints exists (e.g. in the case of a "green field" development), the gas lift conceptual design should commence with the forecast of reservoir outflow and the inflow performance of the well. In the first instance, the rule of lifting as deeply as possible against the minimum back pressure should be applied (in line with the assumptions made at the feasibility stage). See figure 4.23 "Inflow performance Forecast" and "Feasibility". The **near technical optimum**[1] gas rate should be established at this stage (this will be verified later).

One important issue to be addressed at this point is the effect of changing reservoir performance on the timing of gas lift (e.g. wells rapidly going to water, PI decline, rapid reservoir pressure decline). During this feasibility stage some broad brush assumptions should also be made to assess the impact of such changes in performance over the life cycle of the development (i.e. significantly increased lift gas demand in an offshore development - should platform design cater for additional compression etc.?).

The rule at this stage is **"keep it simple"** - do not overcomplicate or compromise the system design based on forecasts which may change significantly once some production history is known. Be pragmatic, and allow flexibility where it can be justified. Bear in mind that often the early years of the development contribute greatly to the cash flow and profitability of the development, and therefore it is better to get the design "right" for this early stage, but build some flexibility to cater for changes in the future. Above all, avoid compromise designs which are neither one thing nor the other, and result in the lift system being sub optimal throughout the whole development. Bear in mind that a workover and tubing change out will almost certainly be required during the life of the well at which time the gas lift design can be adapted to circumstance.

4.2.3.b. Verify Tubing Size:

Tubing selection should primarily be governed by the early inflow performance of the well. In a number of cases the tubing size may be pre-determined by the natural flow period of the well. In any case the flow conduit should be sized by balancing the economic trade-off between well production rate and the cost of the well/re-completion.

Careful consideration should be given at this point to the need for dual strings. At the present time some 10% of gas lift installations in the Group are completed as duals. These completions are both expensive and notoriously difficult to optimise. None the less, duals can offer a cost effective solution when developing stacked reservoirs. In cases where reservoir management considerations clearly demonstrate the need for selective production, the economic case for dual gas lift needs to be carefully evaluated considering the full life cycle of the well (i.e. capital investment, production profile etc.).

If the tubing size had already been determined at the feasibility stage, then it should be verified at this stage. If a new tubing size is selected, a new near technical-optimum point needs to be re-established.

The curves shown in figure 4.23 "Verify Tubing Size" should be generated using the appropriate option in WePS.

[1] Note: The near technical optimum lift gas rate is established by taking a point on the gas lift performance curve at which additional lift gas gives little or no additional production. As a very rough rule of thumb, the value should be approximately 90% of maximum Q Gas Lift or approximately 50% of lift gas rate required to establish maximum Q Gas Lift. A specific example of an approach to establish the NTO is given in ref. 18.

4.2.3.c. The Equilibrium Curve

Chapter 2 and appendix B deal with the equilibrium curve in detail, and illustrate how the curve can be calculated by hand. In reality, the equilibrium curve is generated at this stage using WePS. Assuming that the well performance curve has been established (figure 4.23 Feasibility), then the equilibrium curve can be calculated for the near technical optimum IGLR (injection gas liquid ratio). This curve is displayed by the WePS programme in the form of a Pressure versus Depth plot. See figure 4.23 "Create Equilibrium Curve". A number of equilibrium curves should be generated covering the likely range of reservoir pressures, PI and water cut. Note that this step will be re-visited if a future lift gas volume constraint or change to the assumed FTHP is identified (after verification of tubing size).

4.2.3.d. The Deepest Point of Lift

Having established a set of near-optimum lift gas equilibrium curves, the deepest point of lift can now be established. At present, this is done by hand using the equilibrium curves from WePS. Assuming no major physical constraints exist, this step will determine both the point of lift and the required lift gas pressure see figure 4.23 "Deepest Point of Lift".

Note: It is useful to plot the equilibrium curve in both the pressure versus depth plot, and the pressure versus production rate plot (output from WePS), so that the shape of the equilibrium curve can be examined. If required, these plots can be combined to create a lift pressure vs. production rate plot which will allow selection of the appropriate lift depth. For example, in a low PI well there may be very little incremental production gain from lifting near the bottom of the well. However, on the other hand lifting higher may result in reduced costs for the compression facilities. Similar arguments may exist for a highly under saturated crude where lift gas may go back into solution in the tubing.

The main constraints to be considered at this stage are:

- System lift gas pressure constraints e.g. existing (re-injection/sales) compressors, distribution lines etc.
- The allowable draw down on the reservoir (if limited).
- The depth of the top packer (or any other physically limiting factor - e.g. casing integrity).
- The type of gas lift valve selected (IPO or PPO) as this will affect the available lift pressure at depth if the surface pressure is already fixed (see section 4.4.).

Consideration of some or all of the above will allow a proper selection of the optimum lift depth.

4.2.3.e. The Gas Lift Performance Curve.

Having established the depth of lift and the required gas lift pressure, the gas lift performance curve for the well can now be generated using WePS. The plot of Gas Injection Rate versus Production (see figure 4.23, "Gas Lift Performance Curve") is now used in the first instance to verify that the lift gas rate used to calculate the original equilibrium curve(s) was at, or near, the technical optimum. Note that the lift depth may have changed as the result of step 4.2.3d. This information will be used to verify the earlier assumptions made about the surface facilities (i.e. separator pressure, flowline sizing etc.). If the technically optimum lift gas rate is significantly different (> +/- 10%) from that assumed in step 4.2.3c, then the equilibrium curve(s) should be re-calculated until a more acceptable match is obtained. See figure 4.23 decision box "New technical optimum lift gas Q similar to previous near technical optimum Q?"

4.2.3.f. Lift Gas Requirement for the Field.

Having completed step 4.2.3.e, the lift gas rate and pressure requirements can now be established for a group of wells (gathering station) - or the whole field. In a green field development this step can be accomplished simply by adding the lift gas requirement for groups of wells together. In an existing

field this step is carried out by using the GASALL program associated with WePS to calculate the optimum distribution of available gas to each well. An automatic file transfer facility has been provided to hand off the individual well gas lift performance curves to the Optimisation programme.

The optimised field gas lift performance curve is shown in figure 4.23 "Gas Lift Field Requirements". Note that this figure is neither a GUF curve (see chapter 7) nor a "swing list". Each point on the curve represents the field performance assuming optimum distribution of the available lift gas to the wells in question.

4.2.3.g. Lift Gas Pressure and Volume

In a "green field" design, the balance between lift gas pressure (including kick off pressure) and lift gas volume should be established; see figure 4.23 - "Compressor Selection".

This can be done by minimising the horsepower/bbl oil lifted (Opex) within the pressure constraints established in step 4.2.3d. This calculation is not available as yet in WePs.

From a pragmatic point of view, lift gas pressure is usually determined in discreet pressure steps. Evaluation of the incremental Capex costs should therefore be made by taking account of compressor size/weight/cost, or possibly exceeding a particular pressure specification break-point etc. (Generally, the selection of increased pressure is preferable over increased rate from a purely horsepower point of view. See section 1.4.7.)

If this stage results in a lift gas system operating pressure which is +/- 10% different than the one assumed in step 4.2.3d, then an iteration needs to be made (see figure 4.23).

> *Note:* In order to establish the duty of the compressor, a suction pressure (resulting from an assumed THP) needs to be established. The minimum possible THP should be assumed and verified later.

Having established the incremental field wide production gain (oil, water and gas) as a function of incremental gas lift volume, an economic analysis can be carried out to establish the required total lift gas volume. This will be a trade-off between revenue and costs. If this economic optimum represents a constraint on the lift gas rate previously assumed then this new lift gas volume needs to be re-entered back into the Feasibility stage (see figure 4.23).

There will now be a need to re-visit the earlier assumptions made on the surface facilities with regard to the "back pressure" on the wells. If a different THP yields a significant increase in production then the process facilities, separator pressure and flowline sizes may need to be re-visited. Depending on the complexity of the system, a production system model approach may be justified.

An integrated gas lift conceptual design can now be completed on a sound economic basis.

4.2.4. Gas Lift System and Detailed Well Design.

Having established the **conceptual** well and facility design, a number of detailed design activities can now take place. The purpose of this activity is to focus in on the actual well and facility design and allow the selection of specific hardware.

The following section is intended as an overview of a detailed gas lift string design. A pullout flowchart of the design process is shown in figure 4.24. A detailed discussion on specific string design, including a number of examples, is given in section 4.3 and appendix C. Design of dual completions is addressed in Chapter 5.

It is recognised that a substantial portion of the detailed facilities design will also be carried out at this stage, however this is considered to be beyond the scope of this manual. The gas lift design engineer must be aware of the impact of the facilities design on the gas lift design and vice versa. Good communication between Production Technology Process and Operations Engineering is required at this stage.

Most of the elements of detailed design which follow can be accomplished with the GLUE program.

The essential elements of detailed gas lift string design (following on from conceptual design) are:

- Calculate the equilibrium curves.
- Gas lift valve type selection (IPO, PPO)
- Mandrel spacing.
- Valve design/set pressures.
- Orifice sizing, and check on well stability.
- Measurement and control systems.

4.2.4.a. Calculate Equilibrium Curves.

The equilibrium curves are an essential part of the detailed string design. A range of curves should be generated to cover the most likely operating conditions of the well (e.g. variable PI, different water cuts etc.). These curves, together with the surface lift gas injection pressure, will be used to "fix" the string design.

For detailed design these curves should be generated using the GLUE program.

For an existing well, the well performance must be matched using GLUE (and the equilibrium curve or calculated and measured pressure traverse) to reflect the well operating conditions, both now and in the future.

4.2.4.b. Selection of Gas Lift Valve Type .

A detailed discussion on valve selection and valve mechanics is given in chapter 3. In nearly all circumstances the most appropriate design calls for kick-off valves to be installed in the upper mandrels and an orifice valve (no valve action) to be installed at the lifting depth.

The selection of IPO or PPO kick-off valves depends on a number of factors (see section 3.3). The choice of the valve to be used will have an influence on the string design, and will also determine the deepest point of lift (see section 4.3).

4.2.4.c. Mandrel Spacing

Mandrel spacing is covered in some detail in section 4.3.

The basis for estimating mandrel spacing in the most rigorous way is the Equilibrium Curve in the case of IPO valves, and the Final Flowing Gradients in the case of PPO valves.

At present mandrel spacing is normally done by hand.

A highly interactive design using the Strom method (Design line technique) is available within the GLUE programme. This is currently being promoted as the "standard" method within the Shell Group for mandrel spacing.

It is normally necessary to deal with a number of uncertainties at this point in the design (water cut trends, reservoir inflow and pressure behaviour with time) which greatly influence the equilibrium and flowing gradient curve (and hence mandrel spacing).

It is not possible to give a definitive guide on how these variations in design should be handled. The remarks made in section 4.1. are valid.

- Keep it "simple" - do not overcomplicate or compromise the design based on a forecast which may change significantly as soon as some production history becomes available.
- Be pragmatic, and allow flexibility wherever it can be justified.
- Avoid "compromising" the design such that the lift system will be sub optimal throughout the field life.

- Take workover planning into account (i.e. this would give an opportunity to "tune" the design at a later date when production characteristics of the reservoir/well are better known).
- Avoid over-conservatism in mandrel spacing. Do not design for "worst case conditions" (low PI) or space mandrels too close together as this can also create problems, particularly if the well performance is better than predicted (e.g. unable to unload, valve interference etc.).

A number of mechanical issues should also be addressed at this stage.

- Can the selected valves pass sufficient gas for the kick off process? (see chapter 3).
- Is there a lift depth constraint based on casing configuration or integrity?

Depending on the above analysis valve selection may be re-visited (See figure 4.24).

4.2.4.d. Valve Set Pressures.

In a number of cases these are calculated by hand, or by using a spreadsheet based on the chosen design and the formulas given in Chapter 3.

These pressures can now be calculated using the "Valve Design" facility in GLUE for both IPO and PPO valves, in conjunction with the mandrel spacing program or the "mandrels in place" calculation. The program will also verify that the valve will open and close in the correct sequence. It is important to ensure that the selected valve will allow sufficient gas passage to take place to allow transfer to the next valve. This is discussed in more detail in sections 4.3 and 4.4.

4.2.4.e. Orifice Sizing and Check on Well Stability.

It is very important for well stability to ensure that the correct orifice size is chosen for the operating valve or choke. On the one hand, the pressure drop across the orifice should be minimised to permit the deepest lift point, but too big an orifice will cause the well to become unstable (see sections 4.3 and chapter 6). It should be borne in mind when choosing the orifice that some form of "real time control" e.g. (CAO) will most probably be envisaged. Real time control is accomplished by re-distribution of the lift gas (during, for example, compressor outages) by beaning back the lift gas to a number of wells. The selected orifice should therefore allow the well to remain stable over as wide a range of lift gas injection rates as possible. This is discussed in more detail in section 4.6.

If stability cannot be achieved at the operating depth, or the kick off valves selected cannot pass the required amount of gas, then the valve specification step needs to be revisited. In extreme cases, selection of a different type of kick off valve and re-spacing of the mandrels may be called for (see figure 4.24).

4.2.4.f. Measurement and Control Systems

This is considered to be an integral part of detailed well/system design, and is discussed in more detail in section 7. At the very least, measurement of the lift gas volume and pressure, together with the tubing head and casing pressure should be planned. Control of the lift gas injection rate into each individual well will allow proper optimisation of the field during compressor outages. This subject is also covered in more detail in section 7.4 "Optimisation Using Computer Assisted Operations."

4.3. Detailed Gas Lift String Design

4.3.1. Introduction

There are several ways to design a gas lift string depending on the objective of the design, equipment selected and the prevailing operating conditions [refs. 19, 20].

An extremely important element in gas lift string design is the operating cost **and** the cost of deferred production if the equipment fails:

- **The design should be as simple as possible whilst complying with the objective.**

Clearly, the more complex the equipment in a string, the greater the chance that failure of one element will lead to a shut-in and or a workover - and thus deferred production. In principle, each additional piece of equipment in the string should yield a benefit greater than the total cost generated by adding the piece of equipment.

From the point of view of gas lift string design, the ideal situation is to provide sufficient gas pressure at surface to enable gas injection at the optimum depth, so that no gas lift unloading valves will be required. However, since the surface pressure requirements decrease when the well is on full gas lift, this solution is generally too costly with regard to compression facilities - unless these are already available, or can be used for other purposes such as gas export or pressure maintenance. The difference between kick-off and operating pressures will undoubtedly lead to the need to choke back compressor output in order to control the well during normal production. Continuous choking of the lift gas, apart from being energy inefficient, may also be costly in terms of maintenance of the choke, and in extreme cases will cause hydrate problems in the well.

A lower gas injection pressure should decrease the cost of the surface facilities - although it will increase the number of gas lift valves required.

Eliminating unnecessary gas lift equipment in the well, whilst maximising production, requires rigorous design methods based on accurate data. Without this data (which is often not available), it becomes necessary to adopt a more conservative design. Failure to do so may result in a well that is unstable or inefficient, and will subsequently require remedial work.

To develop the best possible design, it is necessary to establish the relationship between the various parameters relevant to the design and economics of the project. See section 4.1.

The main parameters are:

- Well IPR and reservoir fluid properties.
- Optimum or attainable GLR.
- Diameter and length of the injection and production conduits.
- Attainable injection depth, and corresponding oil flow rate.
- Available gas injection volume.
- Maximum and operating gas injection pressures.

The gas lift string must be designed for the specific type of completion and gas lift valve type selected. In this respect, the design can be either for Production Pressure Operated valves (PPO), or for Injection Pressure Operated valves (IPO).

In the first case, the gas injection pressure at surface is kept constant since the valve operation is controlled by the produced fluid pressure. This allows maximum utilisation of the available pressure to reach the deepest possible injection level. This requires a good knowledge of the produced fluid pressure at the various valve levels in the well to enable correct valve setting and to achieve well stability.

In the second case, the surface gas injection pressure must be decreased in steps to operate the gas lift valves. This allows the unloading valves to be independent of the production pressure at the expense of some injection pressure/depth.

The selection of the most suitable valve type therefore depends on the specific conditions of the well or field in question, and on the available gas injection rate and pressure. (See sction 3.3 for criteria.)

In the following pages a graphical design method is described which allows strict adherence to the theory, and serves to promote a clear understanding of the gas lift design process, possibilities and limitations.

Historically, mandrel spacing has been done by hand. However, this can now be carried out with the help of a computer program.

Ideally the program should follow the same rigorous gas lift principles discussed in this section without taking any shortcuts. It would then be up to the design engineer to decide what design margins are required for the specific case considered, and to optimise the design on economic grounds. Such a rigorous design is not yet available.

There are presently a number of string design methods in use in the Shell Group (Strom, American, equal spacing, etc.) All of them to some extent use "short cuts" and unexplained safety factors.

The computerised design method available in GLUE is a highly interactive modified version of the Strom procedure. The method is suitable for both IPO and PPO mandrel spacing design and is being promoted as the Group "standard". The use of this method is covered in detail in the GLUE users guide and in the program Help screens. It is the intention that this module will undergo further development in 1995 when it will also be incorporated into WePS.

The method described in the following pages is intended to promote a fundamental understanding of the unloading process, and the operation of unloading valves. It is recommended that the reader be familiar with the basics of mandrel spacing before attempting a computerised solution, as this will create a better awareness of the "design" or so called "safety" factors that are included.

4.3.2. Valve Action Controlled by Production Pressure Operated (PPO) Valves

The following steps in the design of a gas lift string are required to determine the number and position of the gas lift valves and mandrels to achieve injection as deep as possible.

The basic steps are:

- The selection of the "transfer pressure" at which the valve should close
- The determination of the "transfer gradient" - the pressure gradient below the valve when the selected transfer pressure is reached.

The following describes the physical process taking place in a conventional single string continuous gas lift installation. An example is given in section 4.3.4 to illustrate the approach to the design.

4.3.2.a. Displacement to First Valve.

When gas injection pressure Pi is applied at the wellhead, the liquid in the annulus is "U-tubed" via any open communication with the tubing (including the open gas lift valves). The gas/liquid level in the annulus is therefore pushed down to a depth at which a pressure balance with the tubing is reached. (See figure 4.1)

This is the maximum depth at which valve No.1 can be placed. The valve should in fact be positioned somewhat higher, enough to provide some 50 psi initial differential pressure between casing and tubing in order to generate sufficient gas passage through the valve to initiate kick-out of the well fluid. This also provides a safety margin to cover errors in pressure gradient calculations.

Note: It is usually assumed that the static level is at surface, and that the static gradient is that of the completion or packer fluid. This is a worst case assumption where no leak off of fluid takes place to the reservoir. This would be the case in a new completion where the reservoir is isolated mechanically or with pills from the tubing and gas lift is required to initiate production.

If the static fluid level is known to be below the surface, as in the case of a well with lower than hydrostatic reservoir pressure and high PI, (i.e. leak off into the formation takes place) it may be worthwhile to determine the additional depth at which the first valve can be placed as compared with the 'full of liquid case'.

Placing the first valve as deep as possible allows subsequent valves to be placed even deeper.

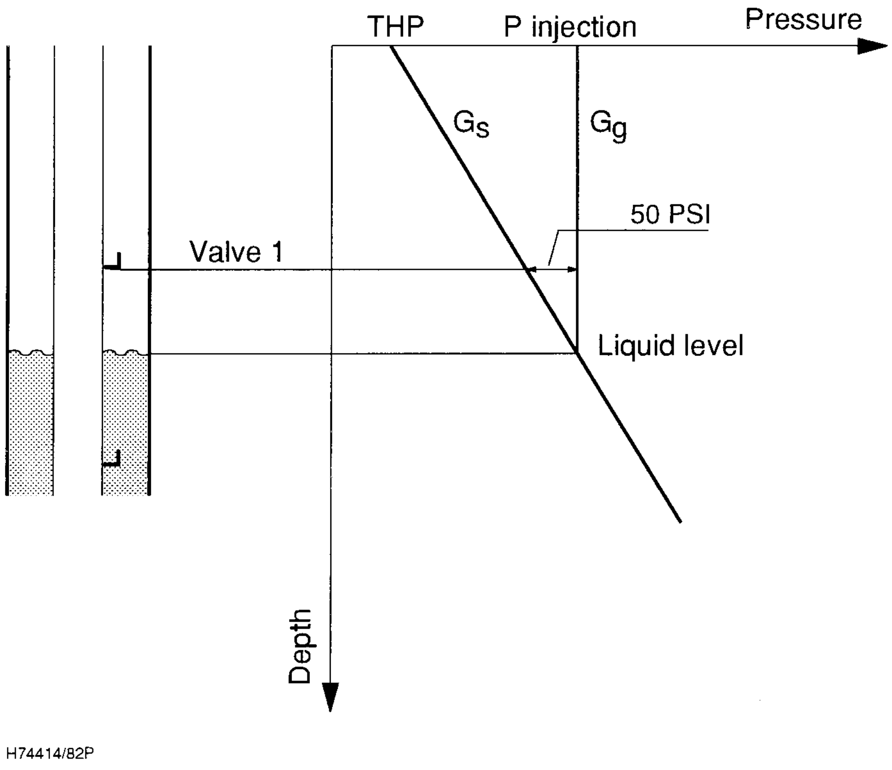


Figure 4.1. - Unloading to first valve.

The gas flowing into the tubing will now displace, and kick-out, the column of fluid above the first valve.

The pressure in the tubing will start to decrease and, unless the valve closes, would continue to decrease until either the residual gradient is reached, if the well is not yet flowing, or the equilibrium pressure is reached.

In practice the upper valve is set to close before this point to prevent it being re-opened when lifting from a deeper valve.

Up to this point, gas lift valve operation has not been required. To move the point of gas injection deeper, it is necessary that a second valve is installed just above the point to where the fluid level has now been depressed by the drop in tubing pressure. (See figure 4.2.)

When the gas level in the annulus reaches the second valve and gas injection has started at that level, the first valve should close shortly thereafter so that all the gas is injected as deep as possible. At this point the different design requirements for IPO and PPO valves become apparent.

When the first valve closes the point of injection is "transferred" to the second valve. At that moment the tubing pressure at first valve level is known as the **transfer pressure** or the 'Pf selected to close valve 1' (P_{fc1}). This pressure is selected by the designer to be as low as possible (to allow the next mandrel to be set as deeply as possible), but higher than the maximum tubing pressure that can be expected at that level when the well is lifting from the final operating depth (to prevent the PPO valve from re-opening).

The design engineer must therefore check the transfer pressure against the flowing pressure that will ultimately be achieved at that depth when the well is being lifted from maximum depth (i.e. the final or ultimate flowing gradient). If necessary, the transfer pressure should be adjusted to ensure that the valve will not re-open after the injection point has been transferred to a deeper level.

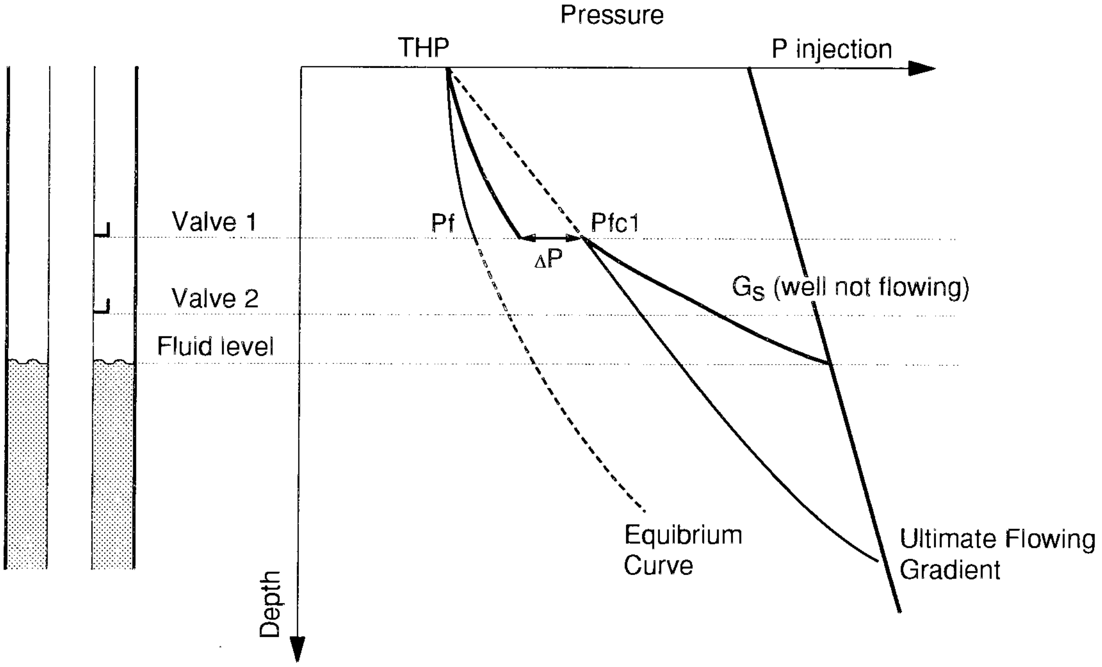


Figure 4.2. - Unloading to second valve.

Where:

THP = Tubing head pressure

P_f = Point on eqilibrium curve at valve 1 depth.

P_{fc1} = Selected transfer pressure

ΔP = Pressure drop across valve 1 just before closing

4.3.2.b. Valve Action

In this rigorous approach, the transfer pressure is selected to be just greater than the ultimate flowing pressure at that depth or, in other words, a point to the right of the ultimate flowing pressure gradient at valve depth.

Sometimes a lower pressure can be specified since it should be remembered that, as the well flow rate increases, the temperature of the produced fluid at valve depth increases. If the valves used have a pressure charged dome to provide the closing force, this pressure and therefore the closing force will increase. If significant, this should be taken into account to select the transfer pressure as this will allow the next valve to be set deeper.

In figure 4.2 the pressure in the casing is defined by the surface injection pressure and the gas injection gradient.

The transfer pressure extrapolated to the next valve depth is defined by the selected transfer pressure and **either**:

- The static fluid gradient extrapolated downwards from the transfer pressure if the well is not flowing. (Gs in figure 4.2.)

or

- The flowing gradient for natural GLR extrapolated downwards from the selected transfer pressure if the well is flowing.

Note: Although the equillibrium curve may indicate that the well will flow when lifting at this depth, remember that the equillibrium curve will not be reached due to the valve action.

Position the next mandrel where there is 50 psi differential between the transfer pressure extrapolation and the lift gas injection pressure.

The transfer pressure at the upper valve depth is used since the action of the valve will not permit the tubing pressure to drop below this value. In this respect a production pressure operated valve acts rather like a tubing pressure regulator. If the valve were not present (or behaved like an IPO valve), then the tubing pressure would decrease until either the residual pressure gradient, or the minimum flowing gradient (given by a point on the equilibrium curve), was reached for the lift gas volume being injected.

The depths of the lower valves are determined by repeating the same procedure:

- Establish the transfer pressure taking account of the final flowing gradient.
- Extrapolate the casing pressure downwards using the lift gas injection gradient.
- Extrapolate the transfer pressure downwards using either the static fluid gradient if the well is not flowing or the flowing gradient.

Choose a depth above the intercept of the tubing pressure and casing pressure which will give a 50 psi differential at valve depth.

Continue spacing valves until either the maximum lift depth is reached or the mandrel spacing becomes too close (less than 100ft is generally used as the rule of thumb but depends on the incremental production).

The selection of the transfer pressure well to the right of the equilibrium pressure explains why the "Standard Spacing" technique is often used for PPO string design (see figure 4.3). The main limitation of the "Standard Spacing" approach is that the design factor at each valve depth is not constant (most of the "safety" is at the top of the string where it is less needed) and there is no check on whether upper valves will open when the final flowing gradient is reached.

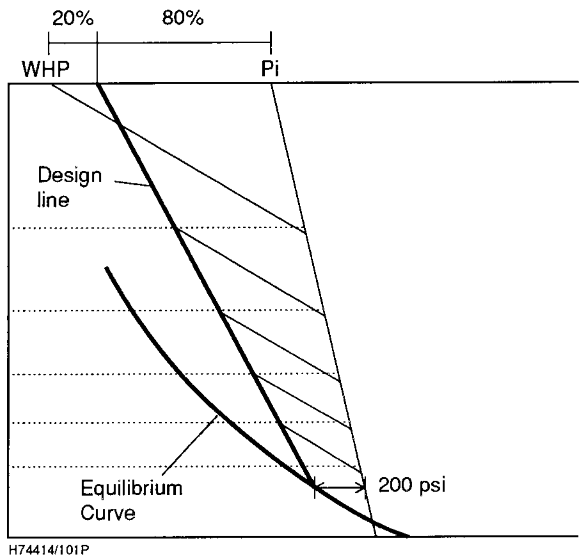


Figure 4.3. - "Standard Spacing" Technique.

4.3.2.c. Bracketing

In some cases due to uncertainties about the inflow performance of the well the design may include **bracketing**. This is the practice of installing a number of mandrels at the bottom of the string at an equal distance apart. Thus if the PI of the well is less than that used in the initial design it may be

possible to transfer lift gas to a deeper valve. Bracketing needs careful consideration, as the potential extra gains must outweigh the increased mechanical complexity.

4.3.2.d. Operating Valve

The final valve is the **operating valve** from which stable gas lift injection should take place over a range of lift gas rates. It is therefore possible, and logical, to install a simple **orifice valve** sized to pass the required gas volumes at design conditions. This will avoid any problems caused by malfunction, or damage of the mechanically more complex gas lift valve.

The use of **active valves** at operating depth is uncommon. The Halliburton (previously Merla) proportional response valve has had a number of trials in the Group over the last 10 years without much success. The valve operates essentially as a PPO valve with a large throttling range. The manufacturer sells this valve on the basis that it can provide stability in the well and reduce heading. Well instability, however, can be quite complex (discussed in detail in Chapter 6) and may not be caused by problems at the injection point. As a matter of fact, slug flow at the top of the tubing is a natural phenomena associated with gas lift (as opposed to more violent heading), and cannot (or should not) be completely eliminated. Not withstanding the above, there are certainly a few cases where such valves can be used to good effect. The advice is:

- Clearly understand the valve characteristics and what it is doing in the well, and if it works for you -then use it!
- Wholesale indiscriminate use of such valves is discouraged. Keep it simple!!

4.3.3. Valve Action Controlled by Injection Pressure Operated (IPO) Valves

4.3.3.a. Variable Gas Injection Pressure at Surface.

The following serves to illustrate the approach required when designing a string using IPO valves

As is the case with PPO valves the basic steps are:

- Selecting a transfer pressure.
- Determining the transfer gradient below the point of gas injection.

The physical process of unloading to the first valve, and the selection of the depth of the first valve, is identical to that described in section 4.3.2 above. It is only when the valve action is considered that the approach to selecting the transfer pressure becomes different.

The main closing force in an IPO valve is the difference between the casing pressure and the bellows and/or spring pressure. The tubing pressure does have some influence on the valve performance causing throttling and will therefore restrict gas passage through the valve (see Chapter 3.). Therefore, consideration should be given to both the casing and tubing pressure when choosing the valve transfer pressure.

In some OPCO's, and in Shell Oil, the "standard spacing" technique (used for PPO valves) has been extended to IPO valves. This facility is available in GLUE.

Whereas a PPO valve acts like a pressure regulator - closing quite rapidly for small changes in tubing pressure - an IPO valve may slowly throttle closed (see figure 3.10). As gas is injected through the first valve, the tubing pressure will tend to drop towards either the residual pressure or the equilibrium pressure. A tubing pressure performance curve versus gas injection rate at valve depth can therefore be drawn. If the gas passage performance of the valve is overlayed with this tubing performance curve (at valve depth), then the intercept of these two lines will indicate the minimum tubing pressure which can be reached. See figure 4.4 below. This pressure can then be taken as the minimum transfer pressure. In figure 4.4. as the tubing pressure moves towards the equilibrium pressure, the valve throttles closed - less gas can pass the valve and so the tubing pressure increases.

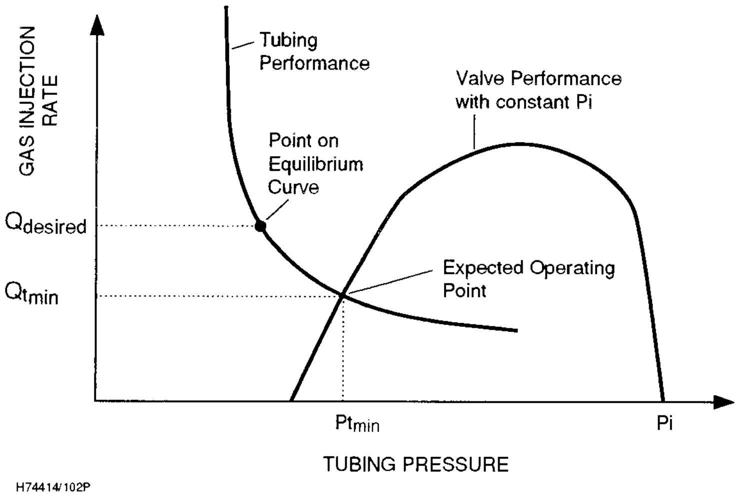


Figure 4.4. - Combining tubing and valve performance.

In the case where the valve does not throttle (choke performance behaviour), the tubing pressure will reach a point on the equilibrium curve. Until fairly recently, most IPO designs were based on the "no throttling" behaviour. It can be seen however, from figure 4.4 that this pressure may not be reached in practice. This is particularly true of the smaller valves (1" or less), where the tubing pressure has more of an influence on valve performance. Care should be taken to select a transfer pressure sufficiently far to the right to take account of the valve action. See figure 4.5

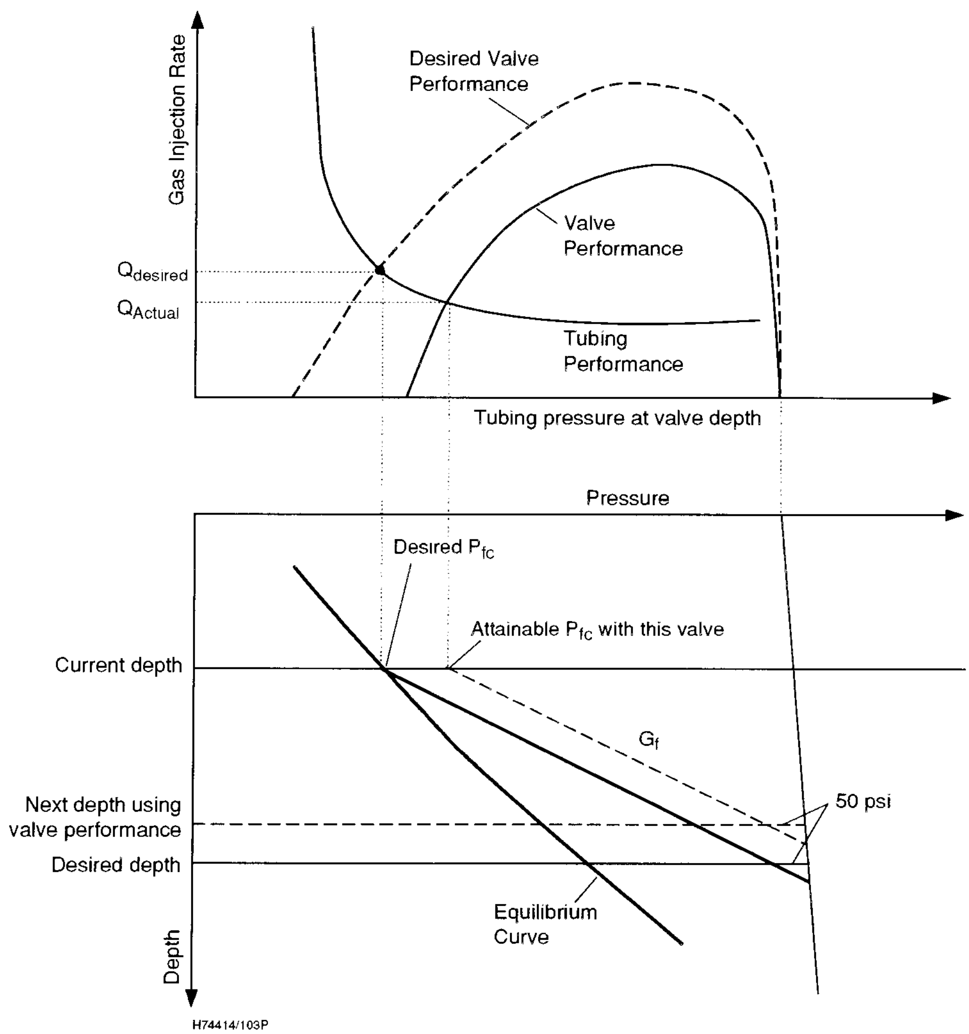


Figure 4.5. - Overlay of valve performance on pressure vs. depth.

Having selected the transfer pressure, the transfer gradient is estimated as outlined in section 4.3.2.

IPO valve action (closing) is arrived at by reducing the casing pressure by a small increment to prevent valve re-opening caused by increases in tubing pressure as the well unloads. This pressure reduction increment may be determined by valve performance (see figure 4.6).

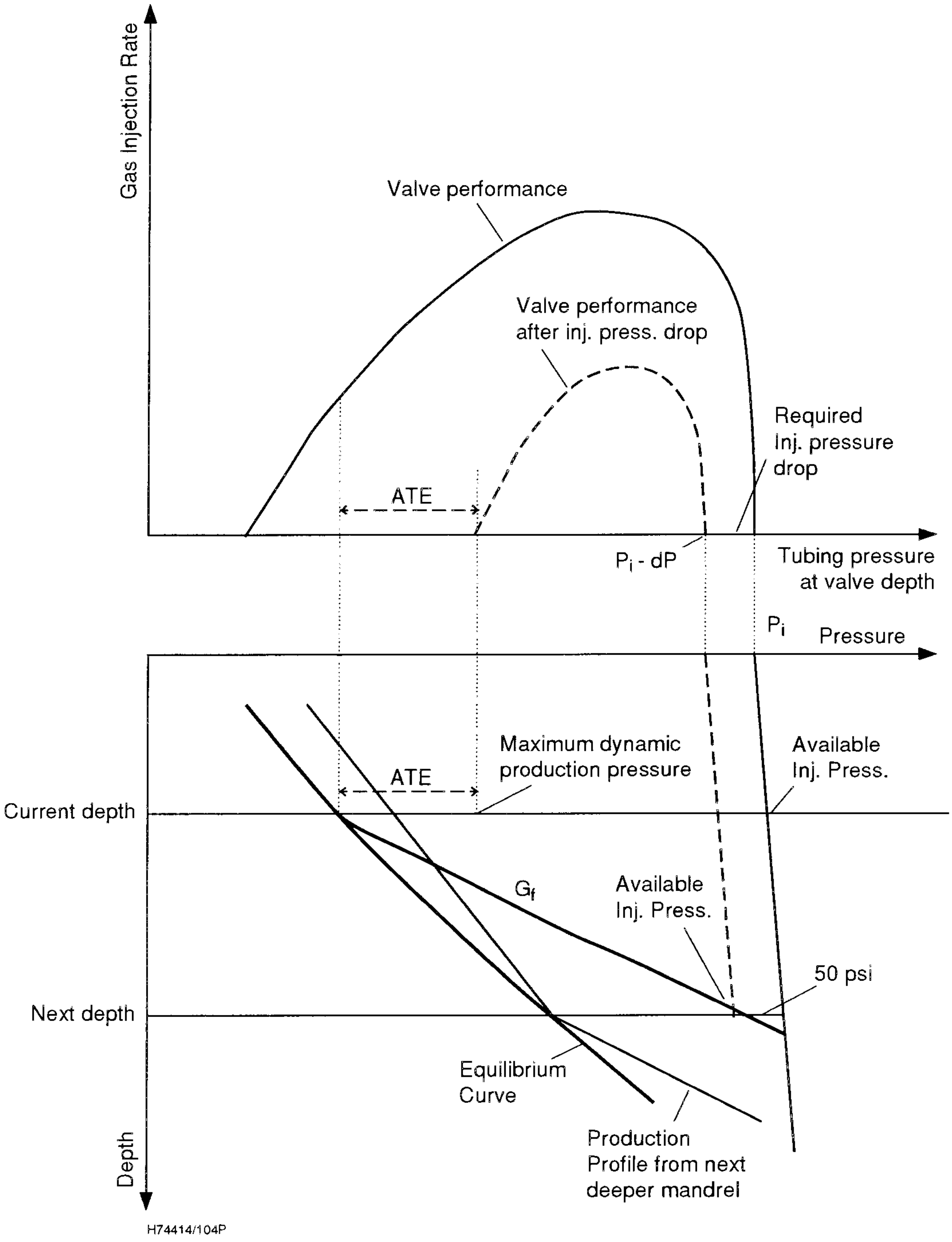


Figure 4.6 - Injection pressure drop to prevent re-opening valve.

The tubing pressure increase is known as Additional Tubing Effect (ATE). The ATE is caused by the production of liquid that has not been gasified between valve depths as the well transfers deeper. This increase in tubing pressure caused by dynamic well performance is difficult to predict without the use of a complex dynamic simulator. An approximation to establish the ATE that has been used sucessfully in Shell Oil is shown in fig. 4.7.

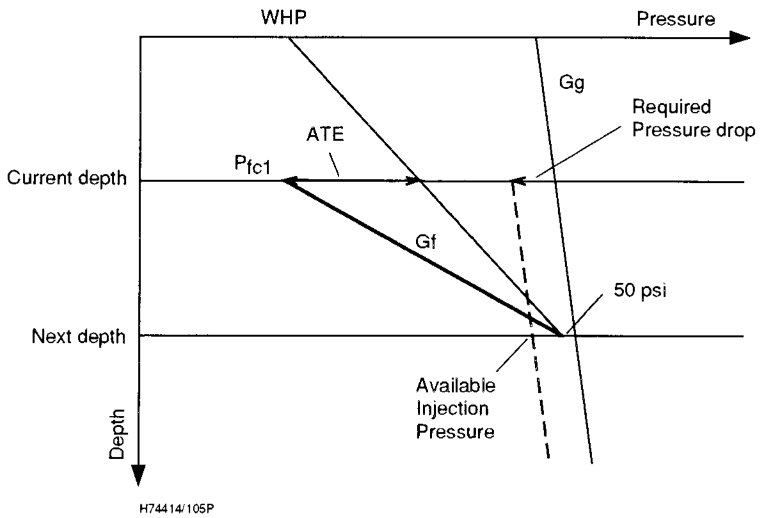


Figure 4.7. - Estimation of additional tubing effect.

In in the absence of valve performance data the minimum required reduction in casing pressure can be calculated conservatively using the ATE and the valve's TEF (see section 3.5.1).

$$\text{Required Pressure Drop} = \text{ATE x TEF}$$

This calculation is performed by GLUE. A minimum of 30 psi should be used. Minimums of 50 or 80 psi may be appropriate for higher pressure systems. Obviously, the smaller the pressure decrements, the deeper gas can be injected for a given surface lift gas injection pressure.

The casing pressure at the second valve depth is therefore found by reducing the casing pressure available at the first valve by a certain amount and extrapolating the lift gas flowing gradient downwards. See figure 4.7.

As is the case with the PPO valve design, a margin of some 50 psi should be used as a design factor when choosing the valve depth.

As the second valve is uncovered and begins to pass gas, the first valve will remain open and the well will lift from both depths simultaneously. If the surface choke on the lift gas line and the gas lift valves have been sized properly, the combined gas flow through the two valves will exceed the flow into the well. The pressure in the annulus will therefore drop until the first valve closes and lift has transferred to the second valve. Assuming that the valve passage of the second valve is sufficient the annulus pressure will not increase and the first valve will remain closed.

The subsequent valve depths are determined by repeating the steps outlined above.The remarks made in sections 4.3.2.c and 4.3.2.d above concerning bracketing and the operating valve are equally valid for the IPO valve design.

4.4. Examples of Mandrel Spacing Design Using IPO and PPO Valves.

The following section gives a graphical example of gas lift string design for production pressure operated valves and injection pressure operated valves.

Further worked examples using actual field data and illustrating some specific points are given in appendix C.1 and C.2.

In order to illustrate the following examples, the equilibrium curves have been generated and used to explain graphically how the design has been accomplished. In reality these correlation's will be carried out using the appropriate routines in WePS and GLUE.

The reader should have a basic understanding of the construction of the equilibrium curve. This is summarised below and explained in some detail in appendix B.

4.4.1. Generation of the Equilibrium Curve.

The following plots are required:

4.4.1.a. Bottom Hole Pressure vs. Liquid Flow Rate Diagram

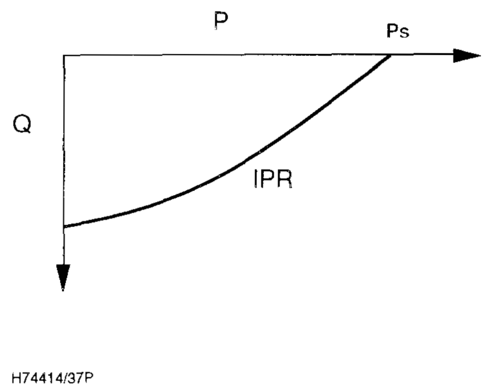


Figure 4.8 - The IPR Curve.

4.4.1.b. Tubing Performance Curves

for natural GLR for Q=Q_{min} to Q_{max}, for a range of depths from 0 to total well depth.

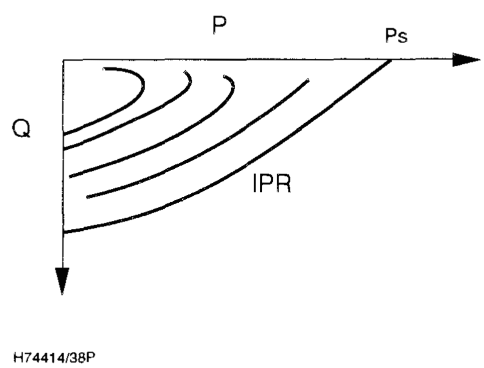


Figure 4. 9 - Tubing performance curve

4.4.1.c. Intake Pressure Curves:

for gas lift GLR for the same range of Q's and depths as above

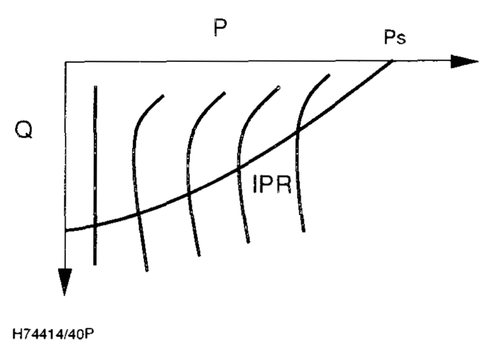


Figure 4. 10- Intake Pressure Curve

4.4.1.d. The Equilibrium Curve

in the P vs. Q plot which is defined by the intersection of curves shown in **b** and **c** above for the various depths.

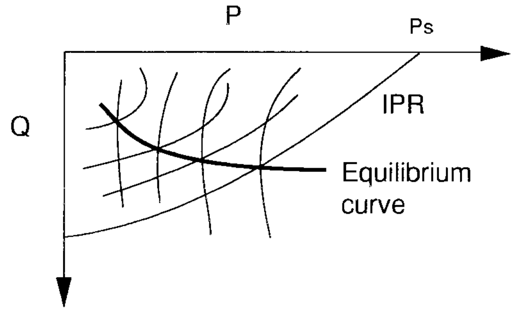


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Figure 4. 11 - The equilibrium curve

Figure 4.12 shows the complete set of curves plotted in both a P vs. D and P vs. Q diagram.

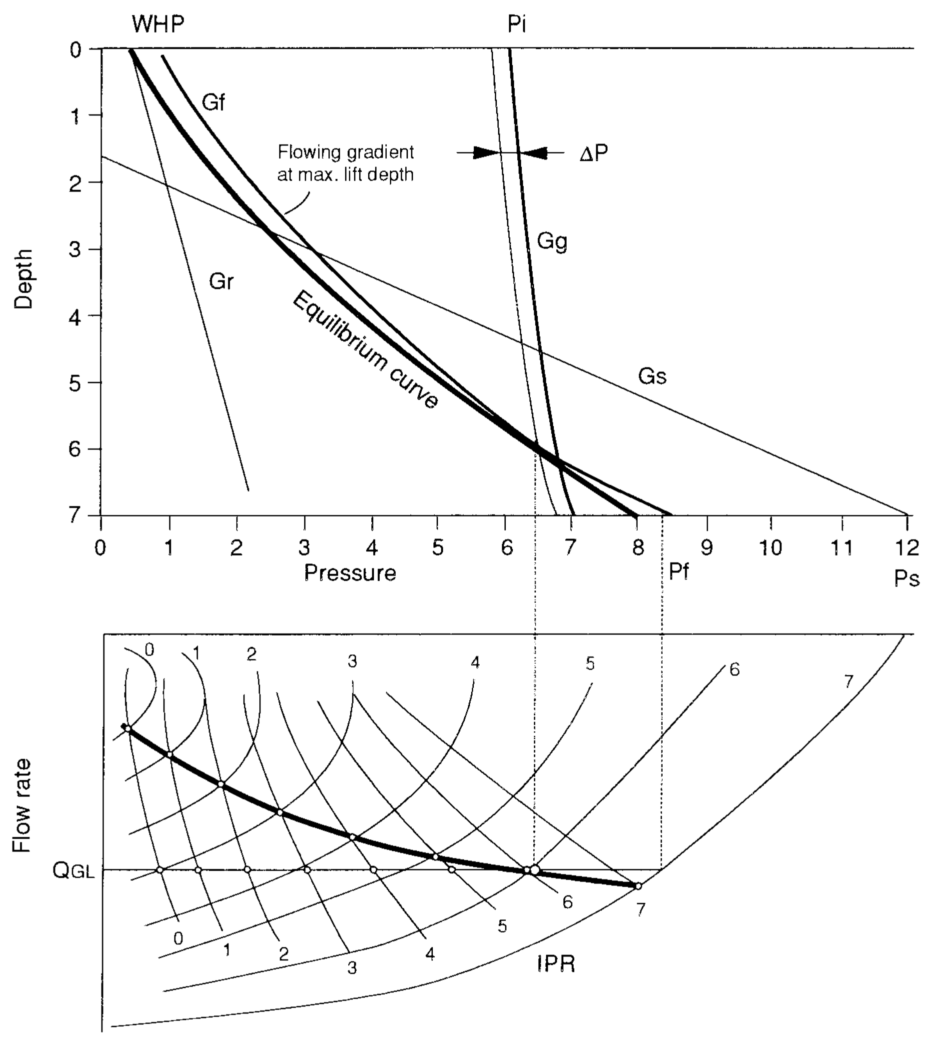

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Figure 4.12 -Pressure vs. Depth.

- The equilibrium curve is plotted by transference of the corresponding pressure and depth data from the P vs. Q diagram above.
- The ultimate gas-lifted produced-fluid gradient is plotted by transference of these data from the P vs. Q diagram at Q_{GL}.
- The gas injection pressure versus depth curve G_g is plotted starting from the surface gas injection pressure P_i using the calculated gas gradient. Note that this gradient may not be constant if the gas velocity is high.
- The initial pressure versus depth lines G_s are plotted for the production and injection conduits i.e. conditions existing in the conduits at the moment of initiating gas lift operations. (fluid level, dead or live oil, kill fluid)
- The residual gradient curve G_r is plotted starting from the minimum surface flowing pressure.The residual gradient is defined as the minimum gradient that can be achieved after displacing a column of dead liquid with the available injection gas (well not flowing).

At this stage, the boundary conditions for the operation have been defined and the pressure, depth, flow rates and gradients data required for the gas lift string design can all be read off from the two diagrams prepared.

4.4.1.e. Design Requirements.

The following basic requirements should be met:

- A valve should be open when the gas/liquid level first reaches that valve depth.
- All valves above the operating valve must close and stay closed. (Unless multiple point gas injection is specifically desired.)
- The operating valve should be able to pass the correct amount of gas to achieve the required gas injection rate.
- The operating valve should be placed as deeply as possible (to maximise drawdown), and still meet the above conditions.

For maximum spacing, each successive (lower) valve is located just above the maximum depth at which the gas/liquid level can be depressed under the conditions generated while injecting the selected volume of gas through the previous (upper)valve. This is done graphically or mathematically by estimating the pressure (and temperature) at injection depth for each step in the unloading operation.

The process ends when the maximum injection depth is reached and the well is flowing at the corresponding gas lift rate, or the mandrel spacing becomes too small.

4.4.2. Example of Design Using Production Pressure Operated Valves.

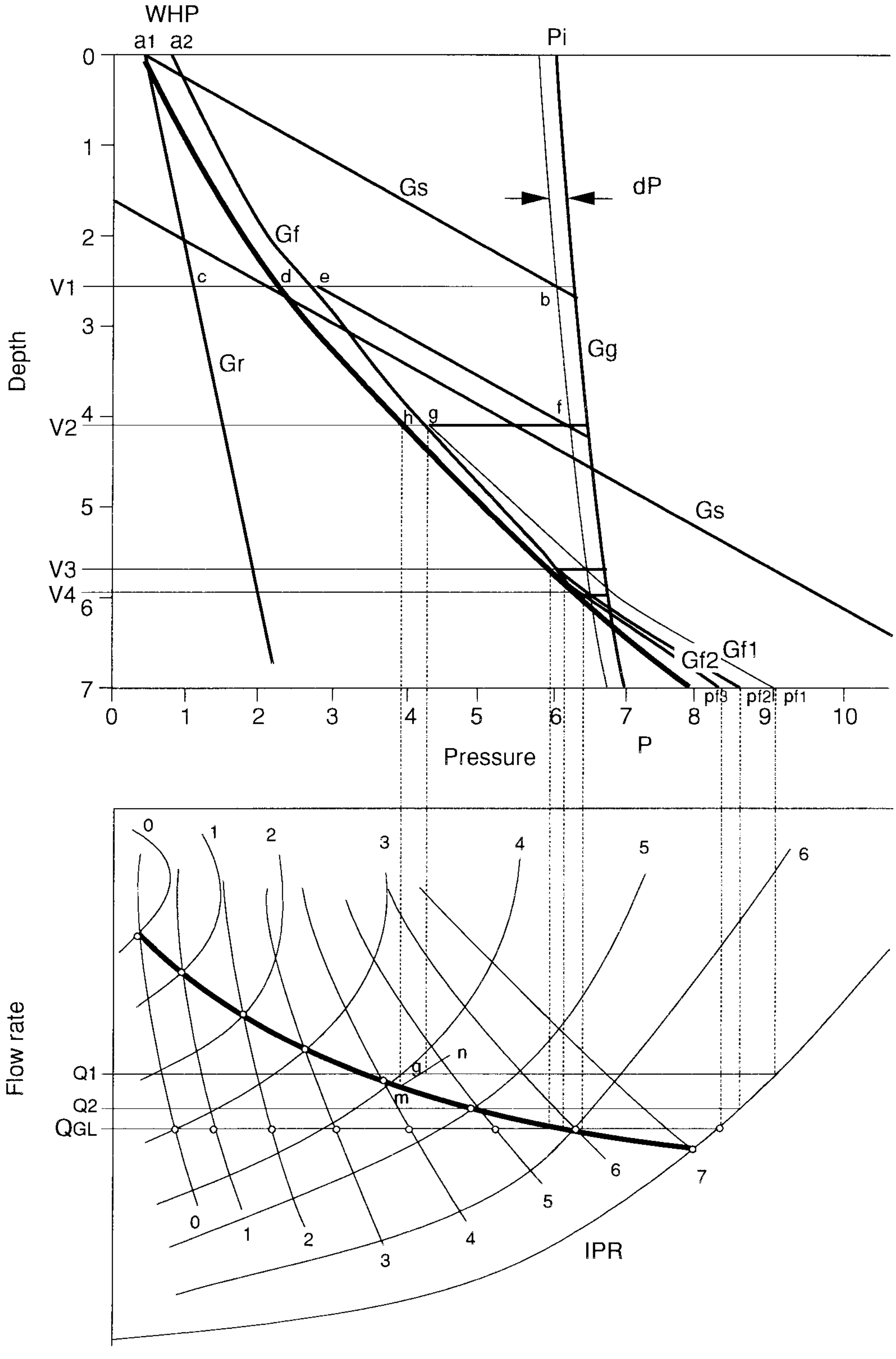

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Figure 4.13. - Gas Lift Design Example

4.4.2.a. First PPO Valve:

Starting at surface with the initial WHP 'a1', the pressure in the production conduit is defined by the static gradient line 'Gs' see figure 4.13. (assuming no leak off to the gradient).

The intersection of this line with the gas injection gradient traverse defines the depth to which the fluid level has been displaced in the injection conduit.

The first valve is placed slightly higher than the above defined depth so as to provide an initial 'dP' pressure differential to ensure gas flow through the valve.

Gas injection at V_1 depth (if no valve is present) would cause the pressure in the production conduit to drop towards residual pressure (point 'c'). Since this pressure is lower than 'd', a point on the static gradient line drawn from the static bottom hole pressure P_s, a drawdown would be induced and the well would start to flow causing the pressure to increase from 'c' to equilibrium pressure. However, later, with gas injection via the bottom valve, the pressure in the production conduit would increase to point 'e' on the ultimate flowing gradient curve. Therefore pressure 'e' is selected as the minimum transfer pressure at valve 1 depth to ensure that this valve will not re-open when the well is lifting from the bottom valve. Note that by fixing the transfer pressure at 'e' this valve will close before the well starts to flow. (i.e. The well cannot be lifted continuously from V_1 depth with the chosen valve.)

4.4.2.b. Second PPO Valve:

Since the well will not flow at the selected transfer pressure the gradient below the point of injection is Gs, the static gradient.

The liquid level in the injection conduit will be depressed to the intersection of a static gradient line starting at 'e' with the gas injection gradient curve. As in the first valve, to provide an initial pressure differential the depth of the second valve is selected at intersection 'f'

The transfer pressure at valve 2 level is selected at intersection 'g' (a point on the ultimate flowing gradient). It is clear that when the pressure in the production conduit reaches point 'g', the BHP is lower than the static reservoir pressure and therefore the well is flowing.

4.4.2.c. Third PPO Valve:

To find the depth at which the liquid level has been depressed at the moment the selected transfer pressure 'g' is reached, it is necessary to define the flowing gradient curve below the injection depth (V_2). To do this, we find the flow rate in the P vs. Q diagram (Q_1) and transfer the corresponding flowing pressures at the various depths to the P versus D plot.

If gas injection at the V_2 level would continue, the pressure in the production conduit would decrease until the equilibrium pressure was reached. The corresponding production rate can be found in the P versus Q plot. However, the valve closes when the transfer pressure 'g' is reached, and therefore the equilibrium pressure, and the corresponding flow rate, has not been achieved at that moment.

To find the flow rate at the moment that the transfer pressure 'g' is reached the following procedure is followed:

1. Find the equilibrium pressure at valve depth in the P vs. D plot.(point 'h')
2. Locate the above mentioned pressure on the equilibrium curve of the P vs. Q plot (point m). As from that point, interpolate a tubing performance curve (Line m-n) which represents flowing pressures versus Q at that particular depth.
3. Locate the transfer pressure 'g' on the interpolated curve.

A horizontal line through that point defines the flow rate (Q_1), and the intersections with the tubing performance curves at the lower levels define the flowing pressures at the various levels - thus the flowing gradient can be plotted in the P vs. D diagram (curve G_{f1}).

The intersection of the flowing gradient curve G_{f1} with the gas injection gradient line (G_g) defines the position of the fluid level in the production conduit at the moment point 'g' is reached. The depth of valve three is selected slightly higher to provide the required dP across the valve. Note how much higher the third valve would be set if the static gradient were to be used.

4.4.2.d. Fourth PPO Valve:

The flowing gradient below depth V_3 is constructed following the same procedure used to define G_{f1}. In this manner flowing gradient curve G_{f2} is constructed.

The depth for the fourth valve is selected as for the upper valves at the intersection of the thin curve parallel to the injection pressure traverse to provide the initial dP.

It can be seen that in this example there is no scope for additional valves since the spacing would be very small and the additional equipment could not be justified, i.e. the theoretical maximum depth has almost been reached. Therefore, in this case, valve number 4 is taken as the bottom valve.

The ultimate flowing gradient curve is adjusted to the conditions obtained: pressure in the production conduit at V_4 depth will become equilibrium pressure and the well will be flowing at the ultimate rate Q_{GL}.

Note that in this example the well head pressure increases to point 'a_2' reflecting the *flow line performance* as the flow rate increases. Flow line performance is an important consideration in the design as it has a direct effect on the ultimate flowing gradient and therefore on valve spacing.

Good design for PPO valves relies on being able to predict the flowing gradients with sufficient accuracy. This requirement is much less stringent in designs for IPO valves.

4.4.3. Example of Design Using Injection Pressure Operated Valves.

4.4.3.a. First IPO Valve:

Positioning of the first valve is identical to the PPO valve design. See section 4.4.2.a.

4.4.3.b. Second IPO Valve:

For the purposes of this example, the transfer pressure for the first valve will be taken as a point on the equilibrium curve, 'e', since this is the lowest pressure that could be sustained at that depth. See figure 4.14.

Note: The assumption has been made that the valves, properly chosen and set, will not throttle closed before the transfer pressure is reached (see sections 3.4.1 and 4.3.3 regarding valve performance). If valve performance data is available, this assumption should be verified.

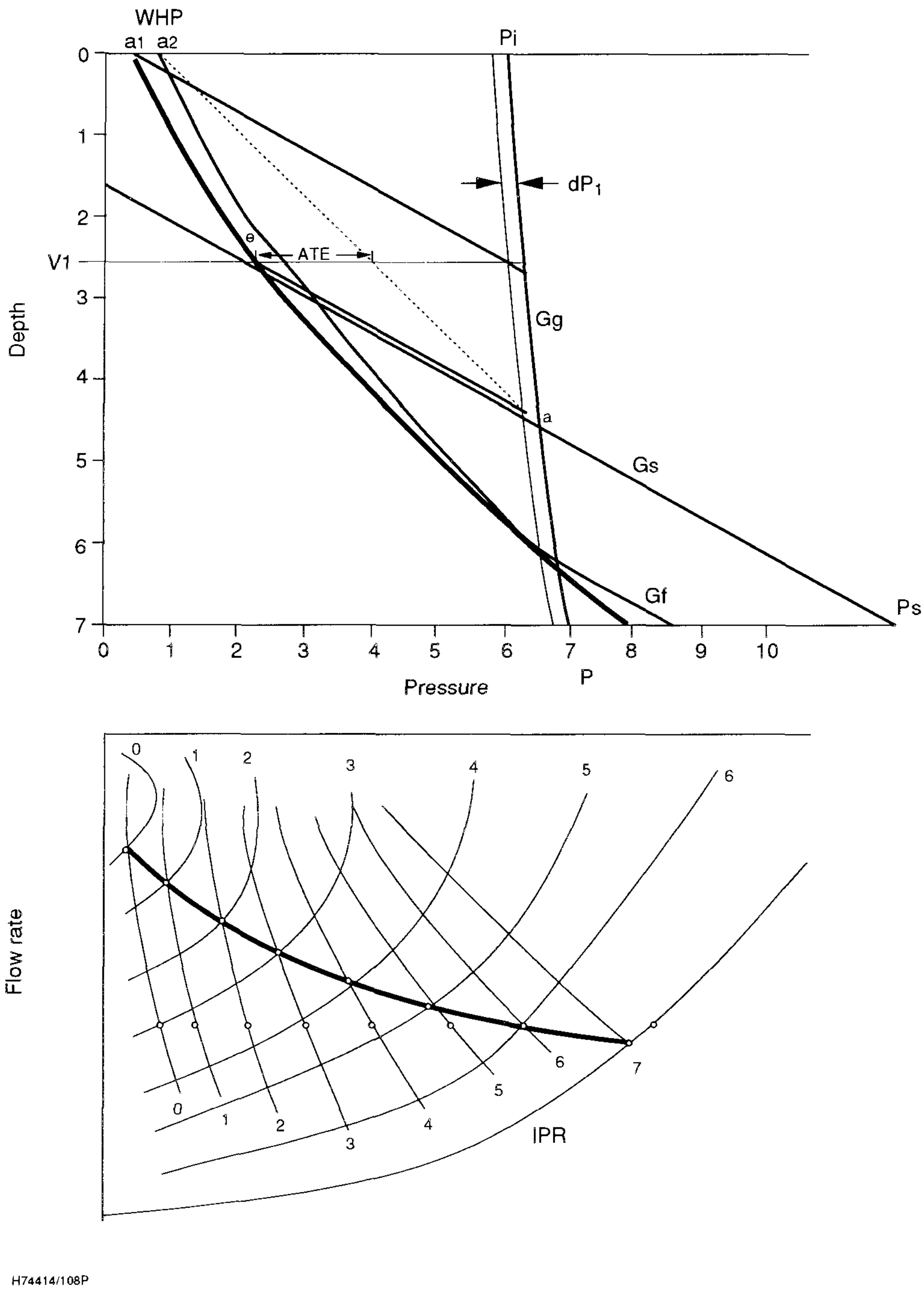

Figure 4.14. - Gas Lift Design Example.

Later, with gas injection via the bottom valve, the pressure in the production conduit would increase to a point on the ultimate flowing gradient curve. However, the IPO pressure decrements for lower valves discussed below are sufficient to ensure that the valve stays closed with the increase in pressure to the ultimate flowing gradient at the first valve depth. This is the reason that the lower equilibrium curve pressure can be used as a transfer pressure to the second valve.

Since the well will not flow at the selected transfer pressure the gradient below the point of injection is Gs, the static gradient.

As mentioned above, the operating injection pressure used for the first valve must be reduced for the second valve to ensure that a subsequent increase in tubing pressure, the Additional Tubing Effect, does not re-open the first valve. (Refer to section 4.3.3 for a discussion on the ATE and pressure drop between valves). The ATE is estimated by projecting a straight line from the point of the intersection of the transfer gradient and the injection pressure (point 'a') to the operating wellhead

pressure (a2), leaving a 50 psi pressure differential. The pressure decrement, dP, is calculated by multiplying the ATE by the first valve's tubing effect factor (TEF).

The fluid level in the injection conduit will be depressed to the intersection of a static gradient line starting at 'e' with the gas injection gradient curve (point 'a').

As in the first valve, to provide an initial pressure differential the depth of the second valve (V2) is placed 50 psi less than Pi (dP1), but also an additional dP less (dP2), at point 'f' to keep the first valve closed. Refer to figure 4.15.

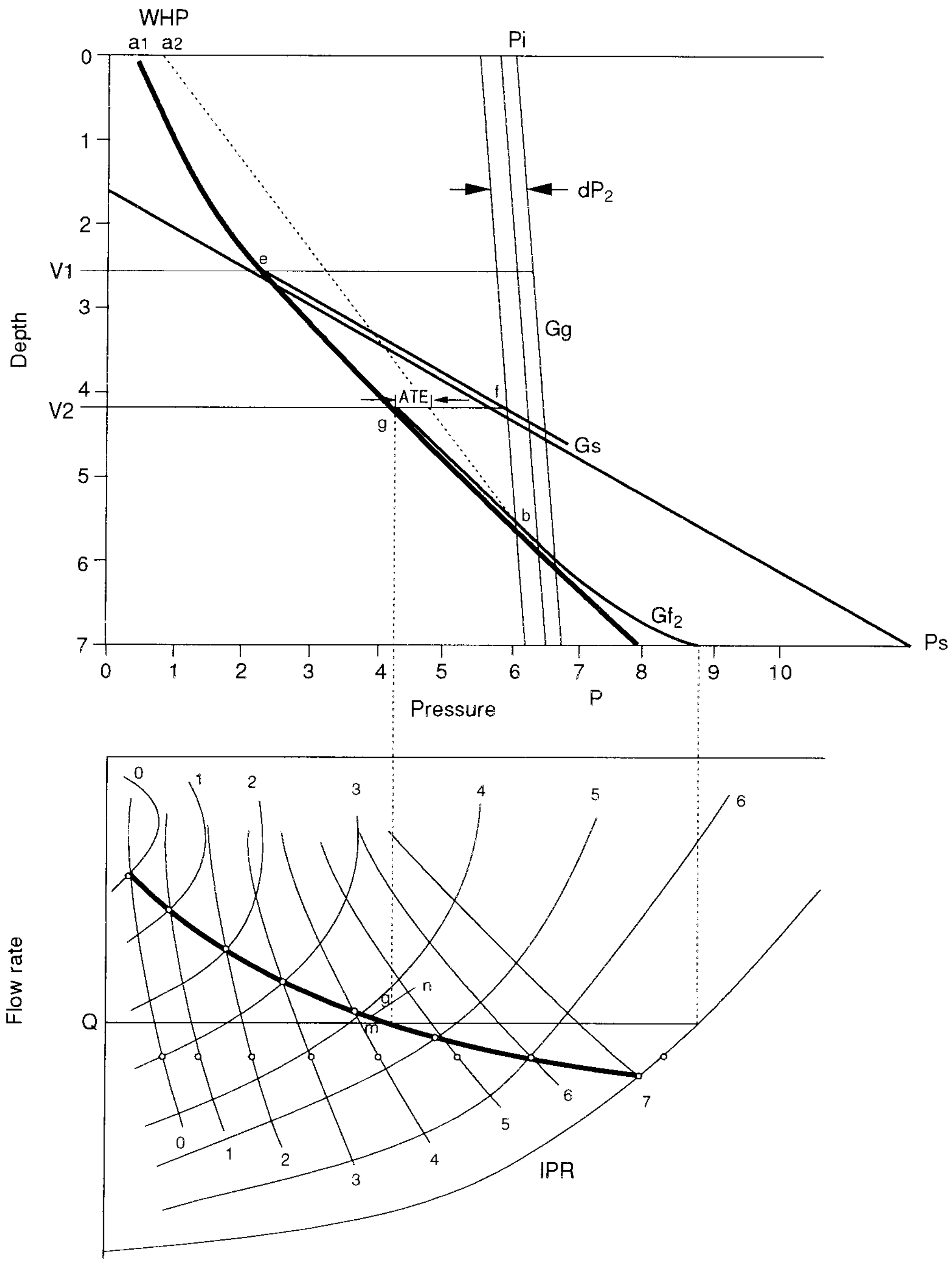

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Figure 4.15. - Gas Lift Design Example

The transfer pressure at valve 2 level is selected at intersection 'g' (again, at a point on the equilibrium curve). It is clear that when the pressure in the production conduit reaches point 'g', the BHP is lower than Ps and therefore the well is flowing.

4.4.3.c. Third IPO Valve:

To find the depth at which the fluid level has been depressed at the moment the selected transfer pressure 'g' is reached, it is necessary to define the flowing gradient curve below the injection depth (V_2). To do this, we find the flow rate in the P vs. Q diagram (Q_1) and transfer the corresponding flowing pressures at the various depths to the P versus D plot as in section 4.4.2.c.

The intersection of the flowing gradient curve G_{f1} with the gas injection gradient line defines the position of the fluid level in the production conduit at the moment point 'g' is reached.

Once again, the operating injection pressure for the second valve must be reduced for the third valve to ensure that a subsequent increase in tubing pressure does not re-open the second valve. The additional tubing effect, ATE, is calculated by projecting a straight line from the point of the intersection of the transfer gradient and the injection pressure (point 'b') to the operating wellhead pressure (a2), leaving a dP1+dP2 pressure differential. The new pressure decrement, dP3, is calculated by multiplying the ATE by the second valve's tubing effect factor (TEF).

As in the second valve, the depth of the third valve (V3) is placed dP1+dP2+dP3 less than Pi at point 'h'. Refer to figure 4.16.

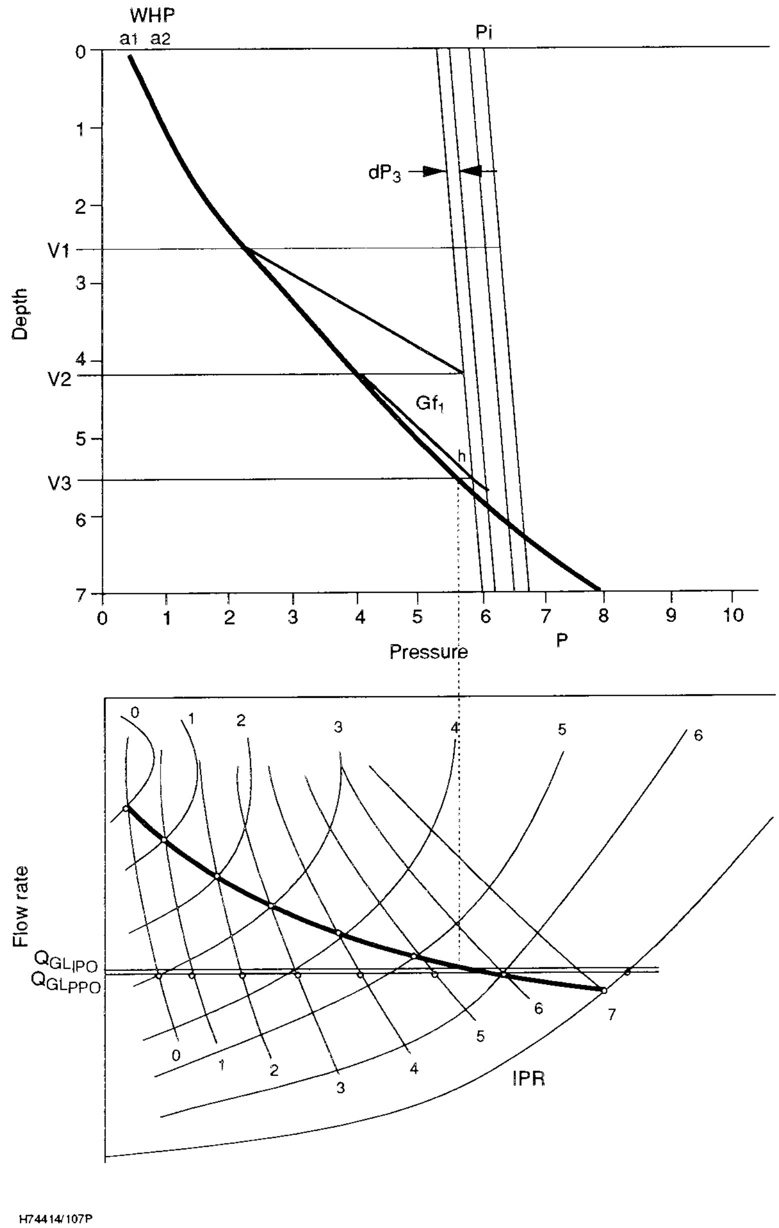


Figure 4.16. - Gas Lift Design Example

It can be seen from figure 4.16. that in this example there is no scope for additional valves since the spacing would be very small and the additional equipment could not be justified, i.e. the theoretical maximum depth has almost been reached. Therefore, in this case, valve number 3 is taken as the bottom valve.

Note: As is typical, less valves have been used in the IPO design compared to the PPO design, but that the maximum depth is less. This will result in less production potential from the design, at least theoretically. In practice, stable single point lift is easier to achieve in IPO designs given inaccuracy in field data and pressure modeling which tends to offset the lift depth advantage of PPO valves.

Also note that the spacing that results from the IPO design may be much wider than a typical PPO design and therefore an IPO design spacing may not be adaptable later for a PPO valve installation. The reverse is generally not a problem.

4.5. Design Factors in Gas Lift.

4.5.1. Introduction

The inability to control many of the parameters that play a role in gas lift design make it necessary to introduce design margins, or design factors, in gas lift string design to ensure that it works in the field.

Historically, design (or so called "safety") factors used in gas lift design have been too large and were poorly understood. The designer should always be aware of the design margins that he is introducing in order to ensure that the system will work within the range of the design margin and that the system does not become unnecessarily inefficient. An over-conservative design may always work, but it is likely to cause substantial deferment of production. The degree of conservatism in a gas lift design should always be clearly documented and challenged.

The worked example in appendix C.1 (case 4) serves to illustrate this point.

Under the conditions of the example given, the generally used assumption that designing for water rather than oil as the well fluid leads to a safe design - proves to be completely wrong for the first gas lift valve.

In some cases, the equilibrium curve has a very gentle curvature, while in other cases its curvature is very pronounced. The same is true of the flowing gradients. Clearly in one case, the use of a straight line to replace the curve could introduce an acceptable error, whilst in the other case a gross error would result. With the availability of increasingly faster and more powerful computer software, there is now no need or justification to take this type of shortcut.

The designer must be careful to avoid "piling up" design factors. Consider the following example:

- To be on the safe side, the crude is taken to be heavier than reported by the field. On top of this, the natural GLR is taken to be lower than the actual, and since a water cut may develop, a 20% water cut is assumed. Generous design margins are thus used in the gas lift design. Clearly, the well is unlikely to flow as indicated by the design, and the efficiency of the system may be questionable. Efforts should be made to obtain good data and then make full use of it.

There is a need to clearly indicate the design factors and assumptions used in the design. In some cases, due to the lack of this information, the Operators in the field can make basic mistakes leading to inefficient operation - or even total failure.

An example of the above is a case where the designer used an operating gas injection pressure 50 psi lower than reportedly available, to ensure that this operating pressure was achieved. However this "design margin" was not clearly reported.

Result:

The reportedly available operating gas injection pressure was correct and the well failed to unload because at that (higher) operating pressure all valves remained open. It was required to introduce a 50 psi drop in the surface injection pressure to allow the well to reach full potential.

It is not feasible to give an exhaustive list of fixed rules regarding design factors for gas lift, since the number of interrelated parameters is so large. However, the following considerations may help to select reasonable design margins.

4.5.2. Pressure Modelling

Assuming that the input data is correct, the pressure gradient curves generated by GLUE, WePS, or similar computer programs provide the best available approximation. However, a margin of error remains. The magnitude of this margin depends on the quality of field data available to enable comparison with the computer output, and adjustment of parameters to obtain an optimum fit for the given conditions.

In gas lift design, the possible margin of error in the gradient curves is allowed for by placing the valves slightly higher than the theoretical maximum depth to allow an initial pressure differential across the valve at that depth. In the examples given in Appendix C this pressure differential has been taken as 50 psi (in most cases) or 20 psi. The range of pressure gradients covered by allowing such a margin is illustrated in figure 4.17

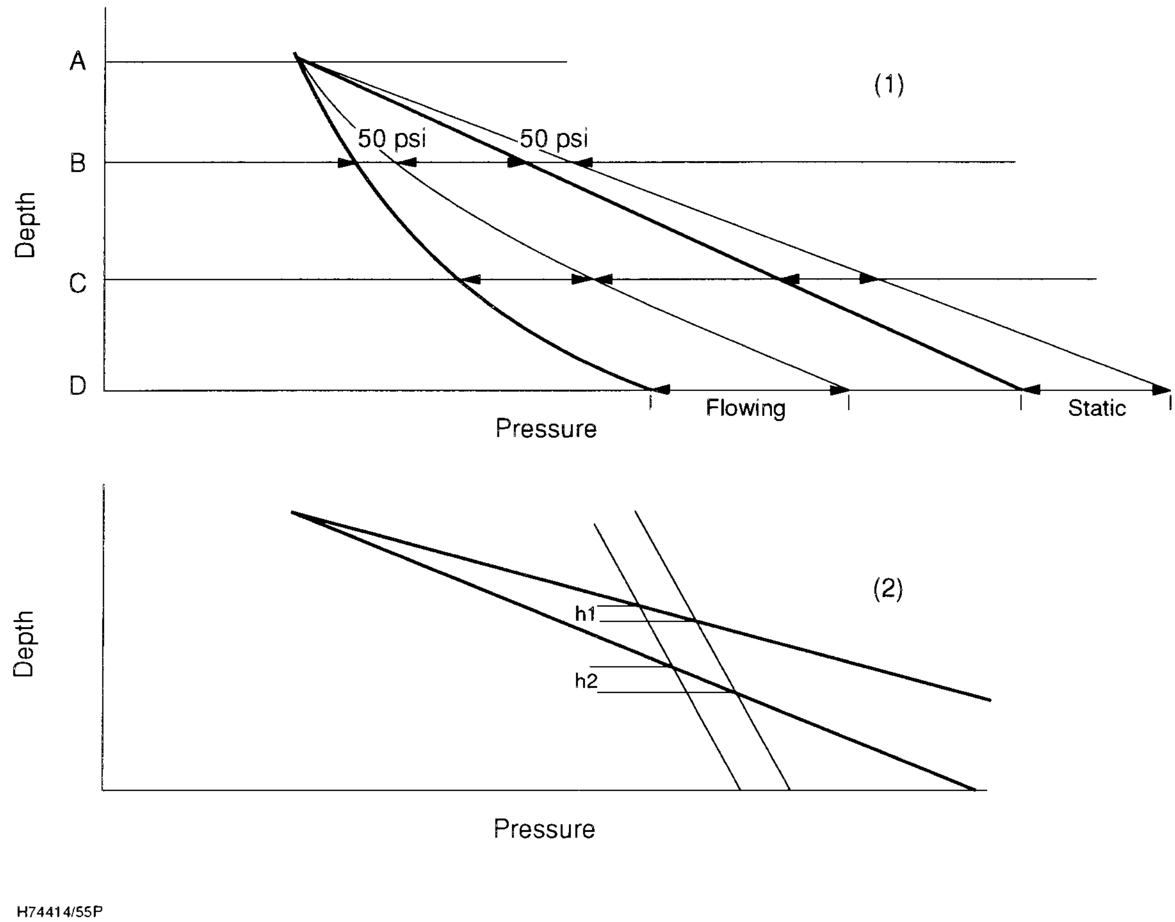


Figure 4.17. - Pressure Gradients margin allowance

In this figure, point A represents the transfer pressure for a gas lift valve. This is a fixed point since it must be reached regardless of the gradient below.

Depth B represents the level of a gas lift valve. At this depth, a 50 psi 'dP' is shown for a flowing gradient and for a static gradient. The range of pressure gradients covered by allowing the 50 psi 'Dp' is depicted between the thick and the thin pressure traverses.

Since the traverses are divergent, the margin of error covered in the bottom hole pressure increases with depth. It follows that if the range of flowing bottom hole pressures, or pressures at next valve depth, are considered too large or too small, the minimum required 'dP' at valve depth can be selected to fit.

> *Note:* also that the error in the flowing gradient represented by the thick line, which is the computer generated gradient, can equally be positive or negative (i.e. the valve spacing could already be conservative).

Figure 4.17 (2) has been added to illustrate the fact that for a fixed 'dP', the depth margin covered increases for the lighter gradients. The common practice of using static gradient lines to define the valve spacing throughout the design, as a further design allowance, can lead to unreasonably high design margins - and therefore to excessively close valve spacing

As an example, refer to the case shown in Appendix C.1.2, Case 2.

In this example, at valve 6 level (4900') the transfer pressure selected was 410 psi. Using the 0.432 psi/ft static gradient to find the depth of the next valve implies that the bottom hole pressure would be 1750 psi. This compares with 1050 psi when the "correct" flowing pressure gradient is used. It is clear that with reasonable well data a 700 psi error in the estimate for bottom hole pressure is far too high to be expected.

If the well data has a high uncertainty, it would be more logical to increase the 'dP' allowed - thus covering a greater range of heavier gradients.

4.5.3. Well Data

For each set of conditions there exists only one "optimum" design. This design will generate the most production with the least downhole equipment.

There are usually quite a number of uncertainties regarding the (future) reservoir inflow performance, the (future) gas liquid ratio, the water cut, and in some cases the flow line performance and facility constraints.

Well conditions may be expected to change during the life of the well. The designer will be challenged with having to create a design that is the best overall, but not "optimum" all the time. In this respect, the gas lift design should be close to optimum early in the installation life, as that is when the bulk of the revenue is generated from the well. In addition, wells may be worked over at a future date giving the opportunity to "tune" the design.

One approach to the initial design is to repeat the calculation for various points in the future where the basic parameters are forecast to have changed significantly (eg PI, water cut, reservoir pressure). Having generated designs for various points in time, it is then necessary to compare (overlay) the required valve depths and decide on a design, or combination of designs, that would be adequate for a sufficiently long time.

It should be remembered that (in most cases) the valve setting can be changed by wireline, but to change the position of the mandrels in the string requires a full workover (or punching holes in the tubing and installing pack-offs). It is of course possible to include some mandrels at suitable depths for future use, but it should be kept in mind that every additional mandrel is a potential source of operational problems.

"Compromise" designs should be avoided or very carefully evaluated. A design for the conditions expected at the end of the field life is likely to be quite different to the design for present conditions. A "compromise" design in that case will be inefficient most (or all) of the time - and may lead to

premature failure if the initial operating injection depth is through a gas lift valve which is expected to close (and not to leak) later on.

4.5.4. Gas Supply and Gas Injection Pressure

The volume of gas available for injection in the particular well for which the design is prepared determines the attainable gas/liquid ratio, and is therefore of vital importance in calculating the equilibrium curve, the intake pressure curves and the gas lift flowing gradients.

The effect of positive or negative changes in gas volume availability are not straight-forward, and if there is uncertainty it is necessary to also work out the design for the maximum and minimum cases.

Considering that a positive control on the maximum injection is normally possible, a reliable available injection gas figure for the design should be obtained.

The maximum and operating surface gas injection pressures at the well head are also critical parameters for gas lift design. An accurate value for this parameter should be measured in the field and/or adequate instrumentation provided to maintain the selected value during gas lift operations, particularly during unloading of the well. A measurement (or estimation) of the operating surface lift gas pressure during injection is required prior to gas lift design so that any pressure losses in the surface lift gas network can be taken into account during the design.

4.5.5. Valve Transfer Pressure

This parameter is selected by the designer from a rather wide range:

- From the residual pressure (well not flowing).
- The equilibrium pressure (well flowing).
- The ultimate flowing gradient.

For maximum efficiency, and to minimise the number of mandrels, the transfer pressure should be as low as possible.

A design margin may be required to ensure that the valve will not re-open later when gas injection has been fully established at a deeper level.

The required design margin strongly depends on the type of valve used, and on the uncertainty in predicted well behaviour.

For PPO valves, the transfer pressure should not be less than the flowing pressure at that level when the well is being produced from the lowest injection point.

The exceptions are dome charged valves where the increase in valve temperature due to increased flow rate is enough to cause the valve re-opening pressure to increase sufficiently to justify the selection of a transfer pressure lower than the ultimate flowing pressure. In all other cases, the temperature effect is used as a design margin and no (or very small) additional margin is required beyond the ultimate gradient.

A practical manner to define a design margin is to select a curve parallel to the ultimate flowing gradient curve as in the examples in Appendix C. The practice of selecting a straight ‘design line’ should be used in conjunction with a good understanding of the valve behaviour to avoid excessive design factors.

For IPO valves, the transfer pressure can be selected at, or very near, the equilibrium pressure assuming the value will pass sufficient gas, since it takes a considerable increase in production fluid pressure to compensate for the imposed decrease in gas injection pressure used to close the valves.

Nevertheless, a check to confirm that the valve will not reopen when the well is flowing on full gas lift is required to avoid surprises. It should be remembered that in most IPO valves the fluid (tubing) pressure acts as an opening force, its magnitude depending on the port area of the valve.

4.5.6. Gas Passage Through Valves

The unloading of a well by gas lift will only work correctly if the rate of gas assumed in the design can actually be injected through each valve. This will ensure that anticipated GLR above the point of injection, and therefore the expected reduction in tubing pressure, can be achieved.

It is therefore critical to ensure that each valve, with the selected port and choke size, can pass at least the required gas rate at the pressure differential defined in the design (see Chapter 3).

When chokes installed in the valves are selected to control the gas injection volume, the freedom to take a bigger choke as a design margin may be restricted. If this is not the case, a larger choke or a larger port can be taken to ensure adequate gas passage, provided the design closing and re-opening pressure can be achieved.

During the unloading process, gas will be injected for short periods through two valves when the transfer pressure is about to be reached (the valve below is uncovered before the transfer pressure is reached). In other words, it is not necessary that a valve can pass the full gas volume until the moment it closes because the valve below has already started to pass increasing volumes of gas. In the case of IPO valves it is of course required that the sum of gas injected through the two valves is greater than the design injection volume to allow the casing pressure to reduce.

4.6. Gas Lift Well Stability.

There are two main areas of instability in single string gas lift wells which are important from a design point of view (Note dual gas lift design is discussed in detail in section 5).

- Instability caused by unloading valve interference or cycling.
- Instability caused by incompatibilities between surface injection choke, lift gas injection rate, well performance and downhole orifice.

There are other effects not directly related to gas lift design such as holes in tubing, pressure fluctuations in surface equipment, etc. These have not been included in this discussion.

4.6.1. Unloading Valve Interference

This is the condition where one or more upper valves are cycling open and closed. This is probably one of the most common causes of gas lift instability. It is caused by bad mandrel spacing, the wrong choice of valve set pressure (or a leaking valve), changes to the flowing conditions of the well or changes to the lift gas rate/pressure.

If a string of **PPO valves** is being used, it is obvious that to prevent the upper valves from opening the tubing pressure must remain below the set opening pressure of the valve. Normally these set pressures are determined using a "static" model and assuming the optimum operating condition (i.e. minimum back pressure, near optimum lift gas rate etc.).

If the flowing condition of the well changes then these assumptions are no longer valid and this may cause the upper valves to open. Some common examples of this would be:

- Well beaned back for any reason using a choke at the wellhead.
- Separator pressure increased.
- Flow line plugging.
- Pigging flowlines.
- SSSV or tubing restriction (eg. build up of wax).
- Lift gas rate beaned back significantly causing the flowing gradient to increase.

In cases where a string of **IPO valves** are used, valve opening results from fluctuations in the annulus pressure. This condition is much easier to detect than that of the PPO valve malfunction, since it is relatively straightforward to determine the injection pressure with depth (without recourse

to a multiphase flow calculation). The casing head pressure will therefore give a very good indication.

In normal circumstances an orifice valve is installed at the injection depth. If this orifice, for any reason, is unable to pass the amount of gas being injected at the surface (normally surface injection is controlled by rate and not annulus pressure) then the pressure in the annulus will begin to build up to the point where one of the unloading valves will open. At that point, the combined passage of the orifice and the open unloading valve may be sufficient to "blow down" the annulus, causing the open unloading valve to close and the cycle will start again. After several cycles it is likely that the unloading valve will "cut out" and then multipoint lifting will commence.

The above problem is exacerbated by close spacing (or similar opening pressures) of the valves. If sufficient pressure is available to reach the deepest point of lift, it is best to take the largest possible pressure decrements when fixing the mandrel spacing and determining the valve settings.

Other conditions which will lead to IPO valve cycling are:

- Fluctuations in lift gas supply pressure when a fixed orifice is used at surface.
- Too big a surface injection choke or choke cutting out.
- Too big a downhole orifice or orifice erosion.
- Surface injection choke bypassed.
- Insufficient lift gas, or increasing tubing pressure, causing well to "die" and annulus pressure to build up.

In addition to the above, both bellows operated IPO and PPO valves are dependent on maintaining pressure in the bellows. Leakage of this pressure will cause the valves to open and lead to multipoint lifting. In this case, the valves will remain permanently open, and will not cycle. Well instabilities would occur because too much gas is being injected at a shallow injection depth. In some cases the well may remain stable, and this condition can only be detected by well testing, or a flowing gradient survey.

4.6.2. Instability Caused by Incompatibility Between Surface Injection Choke, Injection Rate, Well Performance and Downhole Orifice.

Under ideal conditions both the surface injection choke and the downhole choke are chosen based on the steady state solution of the well conditions at the optimum lift gas rate. That is to say, the mass transfer of gas through the surface choke is balanced by the mass transfer of gas through the downhole choke and into the tubing. Note that the term "mass transfer" is used, as the gas volume passage will be different for the two chokes.

If this condition is satisfied then there will be no pressure changes in the annulus. This in itself does not guarantee a stable situation, as by its very nature a gas lift well will almost certainly be in slug flow near the top of the tubing. This will create some pressure surges, which means that the downhole orifice will not pass a constant mass(-rate) of gas. If the system is "stable", these small fluctuations will not cause a major disturbance.

In an "unstable" situation, the fluctuations will become more and more pronounced until the well is **heading** violently, and the casing pressure is changing over a relatively wide pressure range. This in turn may cause the upper unloading valves to cycle as discussed above. A tool to study this process and that of multi-pointing is KSEPL's dynamic gas lift simulator DYNALIFT [ref. 27]. This simulator has been developed to diagnose poor lift performance, evaluate the effectiveness of remedial measures and improve the design of gas lift strings. A number of field cases, encompassing different types of heading and the unloading of wells, have been studied to validate the simulator. Specific field cases can be studied by KSEPL. It is the intention to integrate DYNALIFT with GLUE/CAO at some point in the future to provide this diagnostic capability.

Even if the well is stable at the design operating conditions, instabilities can (and often are) introduced when the lift gas rate to the well is changed (i.e. re-distribution of gas due to compressor failure etc.). In the past, gas re-distribution was normally accomplished by closing in wells (swing list approach), and maintaining the design lift gas rate into the remaining wells. As discussed in section 7. The most efficient method (less deferred oil) is in fact to maintain an optimised distribution of gas to each well connected to the grid. Recent development of Computer Assisted Operations (CAO) hardware/software now makes this possible (see section 7.3.). The issue of well stability (which will define the "operating envelope" for the well) therefore plays a very important role in gas lift well optimisation. The "operating envelope" is determined by both the (economic) optimisation and the stability of the well. The design of gas lift wells should therefore address both issues simultaneously.

When lift gas rate is reduced to a well, the mass transfer at the bottom orifice is initially unaffected, however as gas is removed from the annulus the pressure in the annulus begins to fall. In the case of a fixed surface choke this will cause the mass flowrate of gas across the surface choke to increase and the well will attempt to reach a new equilibrium. If, however the lift gas is controlled by rate control (constant mass passage through the surface choke), the mass flow through the surface choke does not increase and the annulus pressure continues to decrease until a new equilibrium point is reached where the mass transfer out of the tubing equals that of the mass flow into the tubing. There are two observations to be made at this point:

1 The bottom hole pressure has now increased (lower GLR).

2 The pressure drop over the downhole orifice has been reduced (perhaps in some case very significantly). If this pressure drop is insufficient to pass the new mass flow of injection gas then the casing pressure will begin to build until equilibrium is reached. The rate at which this new stable condition is achieved (if it can be achieved at all) is a function of the mass flow rate of the gas, the inflow performance of the well and the volume and pressure of the annulus

As can be seen from the above description of a simple change in lift gas rate, the interconnection of the various parts of a gas lift well are relatively complex, compounded by the stored volume of gas in the annulus and the compressibility of the gas itself.

Much has been written in the literature on this subject.

For general guidance however two approaches can be considered. That of Asheim [ref. 21] and Golan & Whitson [ref. 22].

Asheim is discussed in detail in Section 6. Essentially he maintains that stability is achieved if the rate of pressure decrease in the tubing is less than that of the annulus.

If an **increase** in gas inflow over the downhole orifice causes a corresponding **increase** in the pressure drop across the orifice (i.e. the tubing pressure is falling faster than the casing pressure) then gas inflow to the tubing will increase further. This positive feedback leads to unstable flow behaviour.

If, on the other hand, if an increase in gas flow causes a decrease in pressure drop across the orifice, the flow of gas will decrease, and the well will be stabilised by negative feedback.

Asheim has developed a mathematical criteria based on the above which is discussed in section 6.

The approach adopted by Golan and Whitson is essentially a graphical one and can be used as a design check for stability. They visualise a "node" in the tubing at the injection depth where the well inflow performance, tubing performance and gas lift choke performance should be solved.

If a gas lift well performance curve is plotted this will have a corresponding tubing/inflow performance curve at gas injection depth (figure 4.18). At that same depth the choke performance curve for the gas lift valve can be plotted (figure 4.19). The intercept between the tubing performance curve and the choke performance curve will give the stabilised gas passage through the

choke or valve (figure 4.20). In essence, this is the same calculation which is performed mathematically to obtain the choke size in the first place.

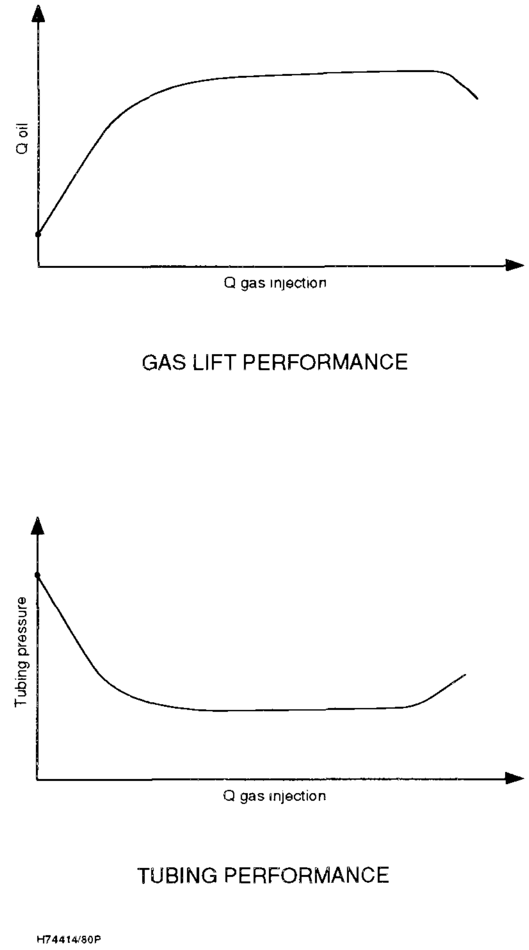


Figure 4.18. - Gas lift performance and tubing performance curves.

The interesting point of the graphical representation is the observation of whether the chosen operating point is stable or not.

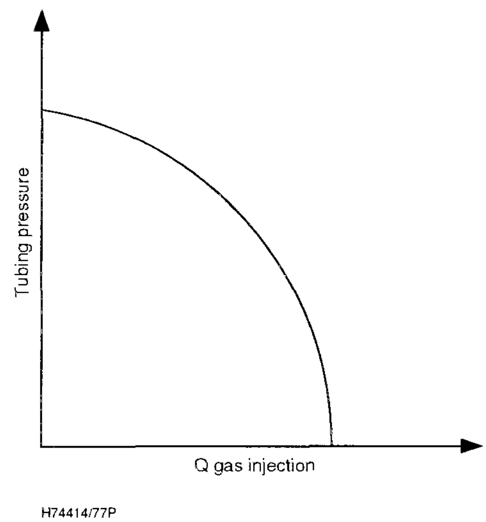


Figure 4.19. - Downhole choke performance curve.

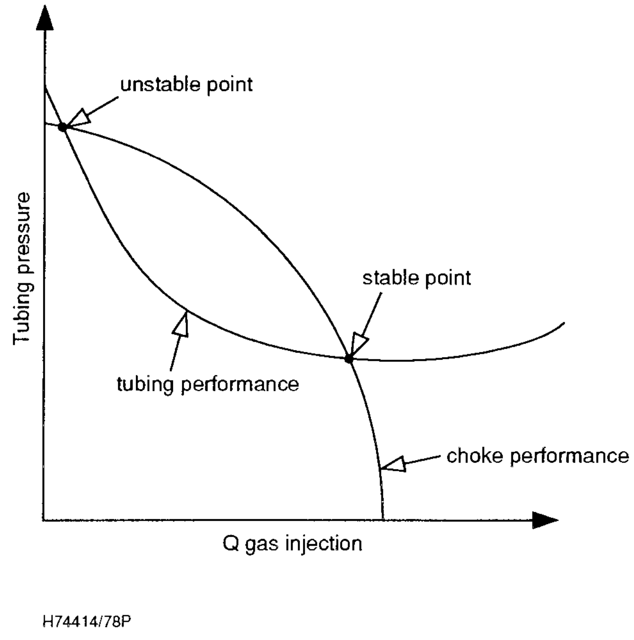


Figure 4.20. - Overlay of choke performance and tubing performance curve.

Golan and Whitson however consider a constant pressure in the annulus. This is the case when there is no surface choke (or the choke is fully open). In fact, as we see from the discussion above, the annulus pressure will move to a new equilibrium as the injection rate is changed. This will have a (significant) effect on the choke characteristics (see figure 4.21).

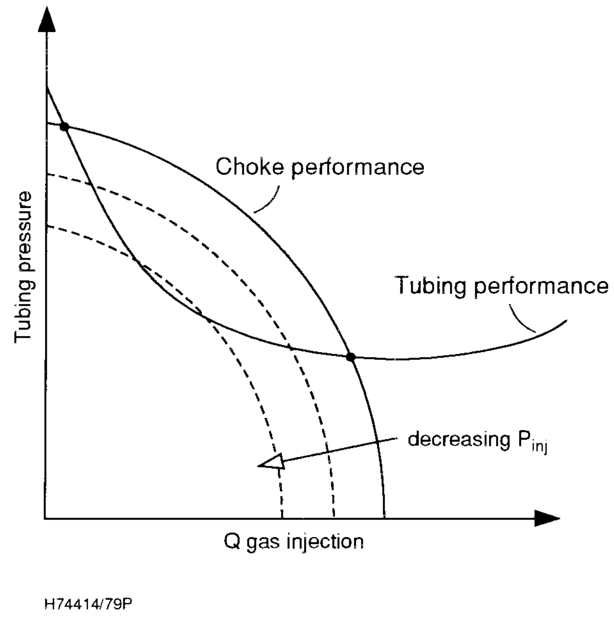


Figure 4.21. - Effect of reduced casing pressure on downhole choke performance.

This change in choke performance will in fact move the well into the "unstable" region at an earlier point than previously forecast.

The above explains why downhole choke control is considered to be better than surface choke control, and why proportional response (or active) valves normally do not have the flexibility to cope with a range of gas injection rates (see figure 4.22).

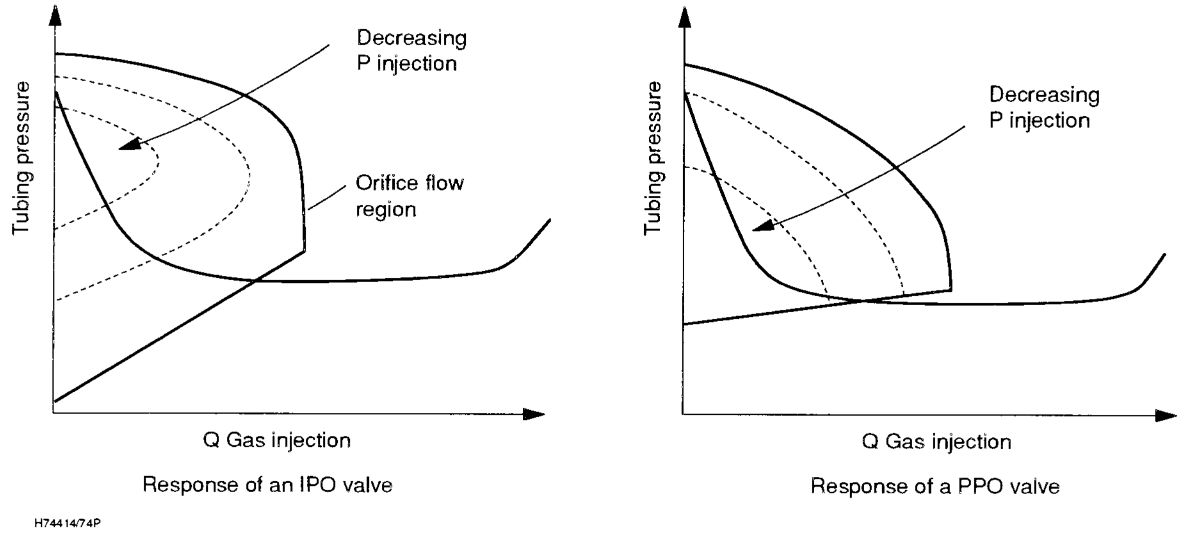
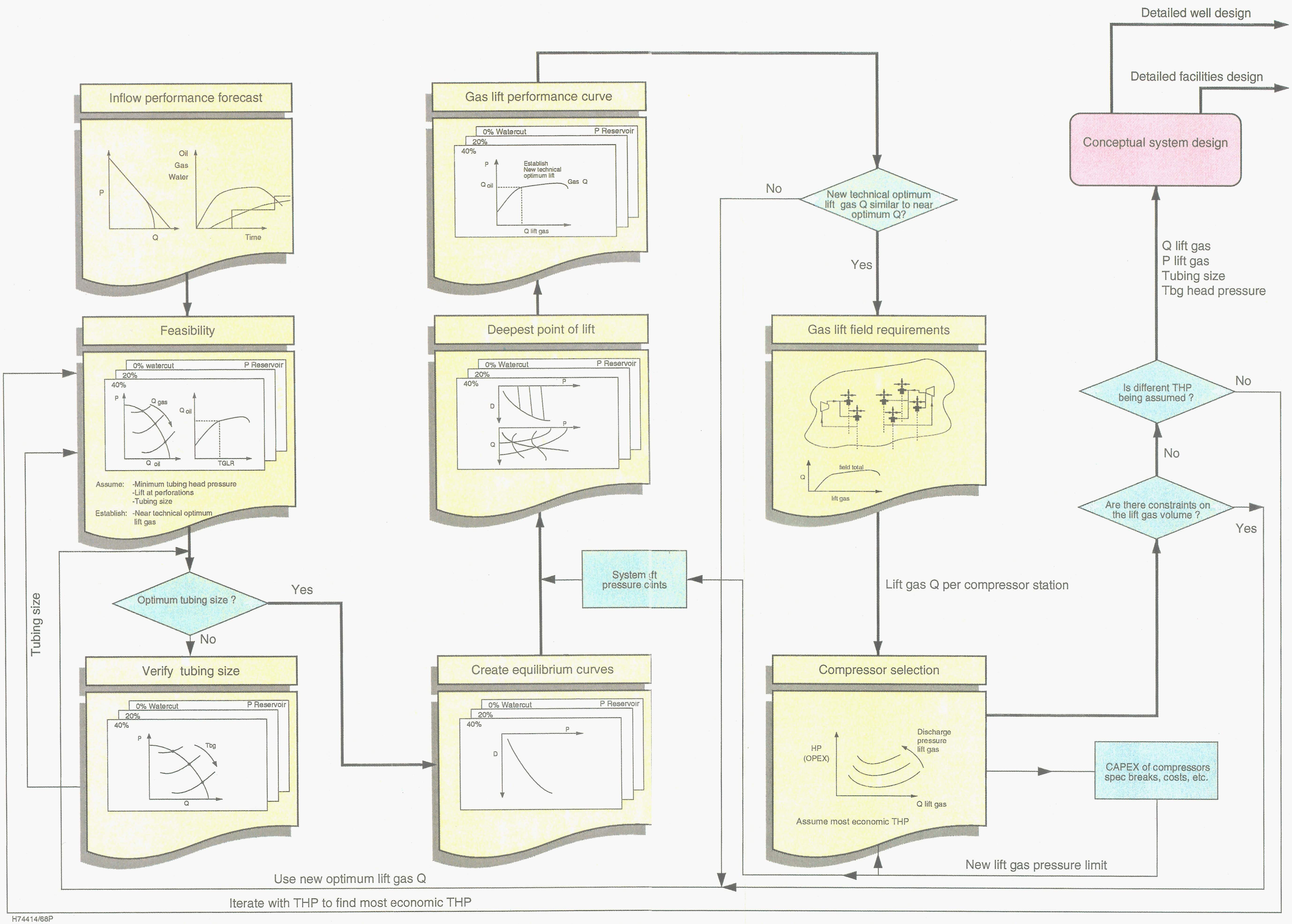


Figure 4.22. - Effect of reduced casing pressure on "active" valve performance

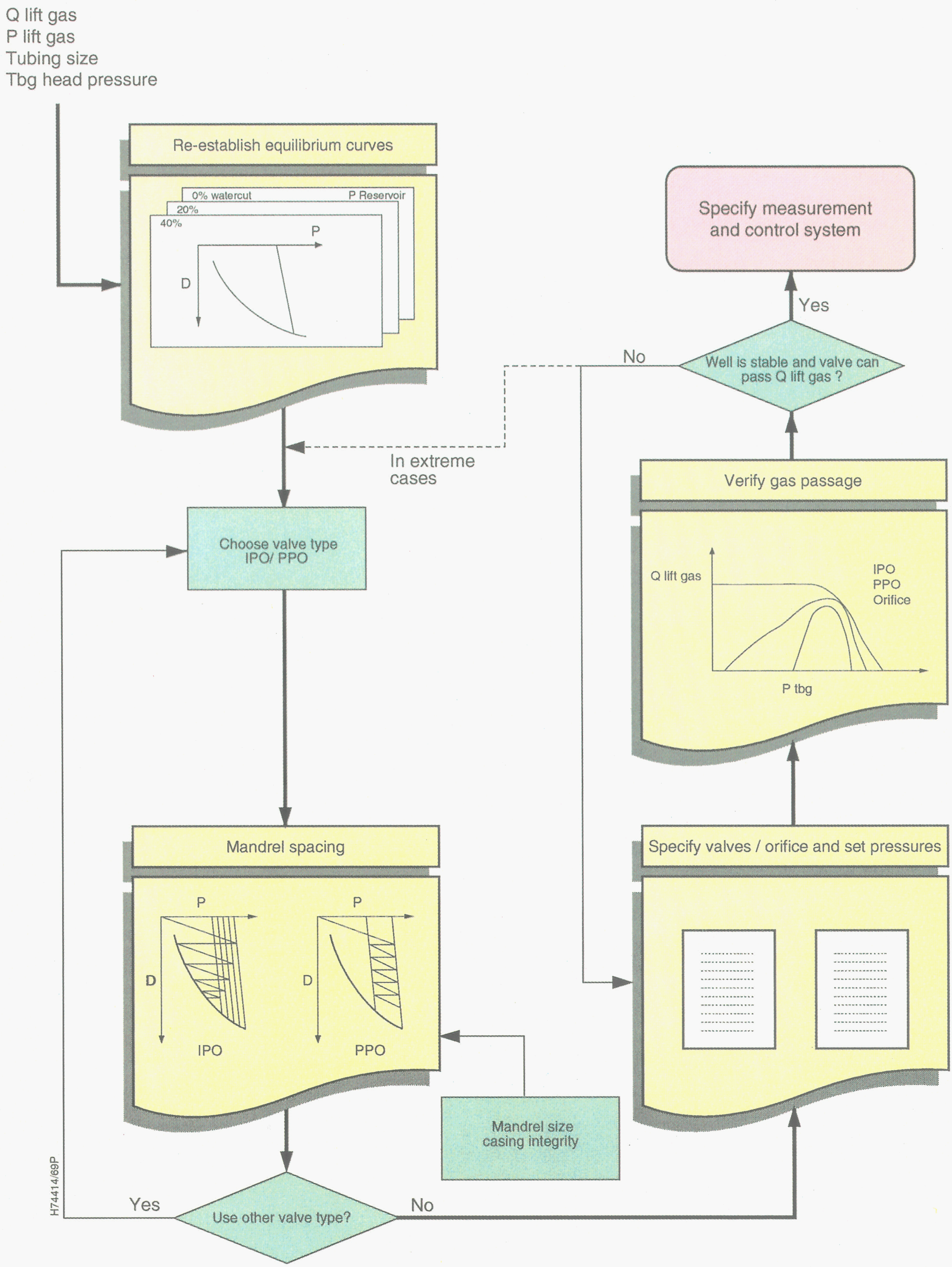
In general, stability is promoted by small lift gas conduit volume (normally the annulus), large PI, high lift gas rate and a small orifice. The last two suggesting that a significant pressure drop across the orifice should be maintained.

API recommends the sizing of the injection port to be chosen such that a pressure differential of at least 100 psi is maintained across the orifice. In the absence of any other criteria this will secure stable operation for the majority of gas lift installations, and can therefore be used as a guide to establish the "turn down" ratio of a given well; i.e. what is the minimum sustainable lift gas rate for stable flow? This will define the lower boundary of the well operating envelope (see section 7). If doubt exists over well stability the above approach can be used or a more rigorous check can be made by KSEPL using the DYNALIFT program.

CONCEPTUAL GAS LIF DESIGN (Figure 4.23)



DETAILED WELL DESIGN (Figure 4.24)



5. GAS LIFT DUALS

The Shell Group continues to operate in excess of 500 gas lifted dual wells [ref. 2]; the vast majority being 3 1/2" x 3 1/2" inside 9 5/8" production casing. Despite many years of operational experience, gas lifted duals remain difficult to operate and optimise:

- The main problem results from each production string sharing a common gas supply annulus. Individual zones generally exhibit widely varying inflow characteristics - controlling gas demand and distribution (with current valve technology) is intrinsically difficult.
- Dual completions are generally more complex and less reliable. A well intervention will result in deferred production from a multiple zone completion.
- Dual production packers obviously limit the depth of gas injection. In some cases this may result in the long string being under-lifted due to reduced drawdown.

From the above it is clear that production from gas lifted duals is seldom optimal. The need for and design of these installations should be carefully reviewed.

5.1. Gas Lift Design for Dual Completions

If both producing intervals in a dual completion require artificial lift, it is normal to design a dual gas lift installation with the annular space as a common gas injection conduit. In this type of completion the injection depth is mechanically limited to the depth of the dual packer.

Other possible 'dual' gas lift installations include the use of macaroni tubing, or coiled tubing, inside the production strings. The gas lift design for such installation is basically the same as for a single gas lift string as discussed in previous chapters.

The problems facing dual gas lift completions having a common gas injection conduit are:

- The possible interference between the production strings during unloading
- Inflow pressure fluctuations, at the operating point or when the injection point shifts from one depth to another as a consequence of unstable flow.

The injected gas tends to follow the path of least resistance, which leads to over-injection into one string at the expense of the other and/or to untimely valve operation, preventing one or both strings from operating at the deepest level. It follows that the way to avoid or minimise the problem is to provide the best possible gas rate control at each valve and lift each string as stabily as possible. The first approach in this case would be to reduce the orifice size in the string taking excess gas.

For dual gas lift design, the importance of obtaining an accurate picture of the pressure in all strings at any point in time cannot be over-emphasised since gas passage through the valves is very sensitive to pressure, particularly when critical flow can not be achieved (which is very often the case at the operating valve).

Sub-surface gas volume control can be provided by either a fixed orifice, or by an 'active' configuration responding to the absolute and/or differential pressure across the valve. If enough excess gas injection pressure is available, then small valves can be selected, or chokes can be installed in the valves to achieve critical, or near critical, flow - and thus minimise the effect of changing fluid pressure on the casing annulus pressure. Proportional response valves, or throttling type valves, are an example of an 'active' configuration. The use of throttling valves however, will complicate the design to the extent that it will be very difficult to predict the effect that the "active" valve will have on the other string.

In both cases; to maintain a constant annulus pressure when the gas injection rate into one, or both, tubing strings is varying requires a reserve of sufficiently high-pressure gas. The more excess gas and pressure that is available, the easier it is to achieve gas rate control.

Another important factor for the design of a dual gas lift installation is the difference in flow performance of the two completed intervals. In the extreme cases if the order of magnitude of the fluctuation in gas rate into one string approaches the total gas requirement for the other, the excess gas availability to enable adequate control may become uneconomical.

There are many possible ways in which to design a dual gas lift installation involving the selection of different valve types, or combination of valves types.

From the operational side, dual string gas lift installations can be designed to unload both with or without help of surface manipulations at the time of unloading.

In principle, the following combinations are possible:

- Production pressure operated (PPO) valves in both strings
- One string with injection pressure operated (IPO) valves and the second with PPO valves
- IPO valves in both strings
- Combinations of PPO and IPO valves in one or both strings.

The main possibilities are discussed below:

5.1.1. PPO Valves in Both Strings

This is, in principle, the simplest option and allows maximum utilisation of available surface injection pressure.

If the gas supply is sufficient to maintain the injection pressure practically constant (i.e. critical flow over the downhole orifice) the two tubing strings can work independently of each other.

The spacing of the valves for each string is carried out as for a single installation. However, the selection of the valves must be made with the need for sub-surface gas passage control in mind i.e. at all points in time the maximum gas passage for each valve should be limited to the design volume. In this way interference between the two strings can be minimised

Furthermore, the design should ensure that only one valve per string remains open at operating conditions, and that during the transfer of injection depth from one mandrel to the next the maximum combined gas passage though the two injection points is limited to the selected value.

In some cases, to further avoid interference, it may be possible to use an initial kick-off pressure higher than the operating injection pressure. When the operating injection depth is reached in both strings, it would require a pressure higher than that available to re-open any upper valve. If, for any reason, one of the two strings is closed-in the injection pressure must be boosted to kick-off level in order to re-start that well. This can be done either by a surface controller, or by the gas lift valves themselves - when orifice size, or throttling range, has been carefully selected.

The unloading valves should be selected to have some sensitivity to gas injection pressure, and designed to operate with the higher kick-off pressure. The lower operating injection pressure is only used to select the throughput capacity of the operating valve of each string, so that at that pressure only the desired gas volume will pass through the valve.

The use of an 'active' operating valve configuration would help to prevent excessive gas injection in the other string when the higher kick-off pressure is present, but this advantage has to be economically compared with the possible additional operating cost due to the increased chances of failure inherent in the 'active' type valves.

5.1.2. PPO Valves in One String and IPO Valves in the Other String

The settings for the production pressure operated valves should be based on the final (lower) operating pressure of the string with injection pressure operated valves. In this way, the PPO string can unload and continue to work after the IPO string is lifting from its operating depth.

When the initial (maximum) kick off pressure is applied, injection at the first valve of both strings will be achieved.

Too much gas will tend to go into the PPO string since the valve is sized for a lower pressure and the valve will not close unless it is sufficiently insensitive to Pi. This over injection can be controlled if necessary by either keeping this string closed in or (temporarily) increasing the THP of the string with an adjustable choke or pressure controller.

Unloading of the IPO string will continue until the operating level is reached. At this point the THP of the PPO string should be decreased to design value to continue the unloading of this string to its operating depth.

If gas supply stops, or the IPO string has been closed-in, it is necessary to boost the injection pressure to design kick-off level so that unloading can continue.

The PPO string can be closed-in and re-opened without affecting the other string provided the injection rate into the well can be changed at the surface.

5.1.3. IPO Valves in Both Strings

In principle the design for each string is carried out as if it was for a single completion.

However, it must be kept in mind that both strings will have to unload at the same time, i.e. valve 1 of both strings will close at the same time when the injection pressure is stepped down to the closing value for those two valves. The same applies to the rest of the valves in the string. This implies that special attention must be paid to the timing of the injection pressure decrements to ensure that both strings have unloaded down to the level of the next valve.

Furthermore, gas lift optimisation (and stable operation) becomes much more difficult as the tubing pressure has little influence on valve action. Lift gas allocation to the two strings can only be accomplished by careful selection of the correct orifice size.

5.1.4. Combinations of Valve Types in One or Both Strings

In some conditions it may prove convenient to use one or more different valve types in one or both tubing strings to accommodate particular circumstances. There are many possible combinations which may work under favourable conditions.

For example the deepest valve of each string can be of the PPO type, while the rest of the valves are IPO. The bottom valve can be of the throttling type to regulate the gas injection at a desired value, but remain insensitive to decreases in the annulus pressure.

5.1.5. Recommendations

On balance the best options would appear to be PPO valves in both strings or IPO valves in one string and PPO in the other. The issue of well stability needs to be carefully addressed.

In general, the designer should avoid complicated string designs, but should be prepared to consider adaptation to special conditions when required.

KSEPL and Halliburton are working on the development of a surface controlled gas lift valve. The basic principle of this valve is to allow the downhole orifice to be changed at surface. Being able to control the orifice in one or both strings will allow "tuning" of dual gas lift strings (one of the major uses foreseen for). Work will shortly commence on a wireline retrievable version of this valve.

6. WELL SURVEILLANCE AND TROUBLE-SHOOTING

6.1. Well Surveillance

6.1.1. Data Gathering Requirements

Data gathering is essential for control and optimisation of a gaslift system. Routine data gathering at appropriate time intervals will pay off, not only for routine production performance monitoring, but will also allow optimisation and predictive, preventive, and diagnostic analyses. In many cases unnecessary data is requested too frequently, or on an ad hoc basis, and gathered utilising inappropriate means. Data gathering needs to be properly justified as it is expensive and often results in oil deferment. It may appear difficult to justify routine data gathering on an apparently smooth operating system. Remember, gas lift inefficiency and even failures may not be apparent without additional data gathering. Collect accurate data while you can do not wait until a problem has developed. Try to show the potential benefits by analysing historical cases, and quantify the losses which could have been prevented assuming data availability.

It is recommended that data gathering is conducted in a routine campaign approach following a clearly defined strategy which includes **all** parties (i.e. Production Technology, Reservoir Engineering, Process Engineering, Operations etc.). If not already known, all parties should decide on the operating boundaries of the field (e.g. composition, capacity, liquid handling capacity, production allowables, reservoir withdrawal limits.)

The strategy should be to take a **minimum amount** of **applicable data** utilising **appropriate methods** to maintain control over the system. The data gathering strategy should also include statements on sampling frequency, why the data is required and how (and by whom) they will be used. A good strategy with consensus of all parties will be much easier to propose and defend. A yearly review of this data gathering exercise is recommended.

Usually a combination of measurements is required to carry out an interpretation on system performance. The following list summarises the various measurements and procedures used to analyse a continuous flow gas-lift installation:

- Visual inspection and checks on surface installation.
- Recording of surface pressures at casing, tubing, choke, production manifold and injection manifold.
- Measurements of gas volumes: injection gas, total gas.
- Surface temperature reading at injection manifold and wellhead.
- Well tests to estimate gross rate, BSW, total GLR.
- Downhole pressure and temperature surveys under static and/or flowing conditions.
- Downhole flow and gradient measurements by production logging.

6.1.2. Surface Measurements

6.1.2.1. Visual Inspection

Visual observations made on a gaslift system (at the well head, injection/flow lines, injection manifold, etc.) can be indicative of the efficiency of the lift process. A visual check by the Production Operator should be the very first step in data gathering to ensure that the surface equipment is in good order and that the subsequent measurements are representative.

Visual observations include surface leak detection, gaslift controller checks, etc. A smoothly operating gaslift system can easily be distinguished from a heading system. It is essential to ask the Operator in the field (who sees and hears his equipment very frequently) about his opinion.

6.1.2.2. Surface Pressure Recording

Surface pressure recording is essential in understanding what is happening downhole. Pressures normally recorded at the well head are:

- Injection pressure (at the casing inlet).
- Flowing well head pressure (at the tubing head).

Injection pressure analyses can be used to monitor and verify the unloading process in cases where IPO valves are used. During routine operation, changes in injection pressure can give indications on valve problems, plugging, leaks, injection heading, surface problems. (e.g. hydrate formation, etc..) Compare injection pressures between wells. Low injection pressures may indicate the potential for deeper injection, or the fact that the well is lifting from an upper valve.

Flowing well head pressure (tubing head pressure) recordings can give indications on lift performance, back pressure fluctuations, production heading, etc.. Maintain the tubing pressure at as low a level as possible. This will increase the efficiency of the lift system. Lowering THP may require lowering separator pressure or 'switching' the flowline from a HP to a LP system.

For more detailed pressure recording interpretation, reference is made to pages 379 - 434 from vol. 2a, "The Technology of Artificial lift Methods" by Kermit E. Brown [ref. 4, 14] which gives a range of possible problems and symptoms that can be derived from pressure charts. In addition reference is made to section 7.2.

Compare tubing head pressures to manifold pressures. High pressure drops may indicate flowline or choke plugging. The benefits of lowering tubing head pressures can be quantified with WePS or GLUE.

6.1.2.3. Gas Measurement

Appropriate measurement (and adjustment) of (lift and produced) gas streams is fundamental to gaslift optimisation. Lift gas is expensive due to the compression CAPEX and OPEX and should be utilised optimally. In some cases gaslift systems are operated with excessive lift gas usage. Large savings can be made by economising on gas usage, and often the installation of new compression equipment can be deferred or cancelled. Lift gas optimisation is discussed in detail in chapter 7.

Gas measurement is generally carried out at the following points:

- Gas injection manifold on the gas injection line (or at the wellhead),
- At the test separator to determine the total GLR.

Gas routed to the well needs to be measured to control and optimise the field-wide lift gas distribution, and to analyse lift performance of the well. Total GLR is required to monitor the GOR of the well and to verify the amount of lift gas received (if the GOR is known and constant). This measurement could give the first indication of a casing leak or lift gas injection into the reservoir for example.

Gas measurements and rate adjustment can be carried out by means of controllers, orifice plates, chokes etc.. Bear in mind that orifice plates need to be inspected on a regular basis (annually) to check their condition. A detailed description of gas measurement equipment falls outside the scope of this document, but reference is made to the relevant sections in the Production Handbook.

6.1.2.4. Surface Temperature Recording

Surface temperature recording can be carried out at the following points;

- Ambient temperature at the nearest production station.
- Injection gas temperature downstream the controller and downstream of any chokes.
- Flowing well head temperature at the tubing head.
- Separator temperature at the separator and/or test separator inlet.

Temperature recording of the lift gas can be used for hydrate detection and gas gradient calculations.

The ambient temperature can be used for hydrate prediction and compressor efficiency calculations.

The wellhead temperature can be used in some circumstances as an indication of flowrate.

Test separator temperatures are required for gas and fluid volume corrections.

6.1.2.5. Well Testing

Well testing is carried out to monitor produced liquid and gas flows. From a gaslift point of view, system performance and the impact of system adjustment can be monitored. Well streams are individually tested through a test separator. For representative testing, the flow/test lines need to be properly purged, and the production from the well should not be interrupted in order to ensure testing under stabilised conditions. The test separator pressure must impose the same wellhead production pressure as the bulk separator in order to simulate normal production conditions. During well testing the gross rate, net oil rate, water content and gas rate are measured. Changes to any of these parameters over time need be monitored closely. The gas lift design assumptions need to be verified at regular intervals. Trend analyses can give good predictive indications on when a gaslift design needs to be revised, and related activities can be scheduled accordingly.

Be sure to get representative tests in conjunction with flowing pressure surveys. (See section 6.1.3.)

6.1.3. Sub Surface Measurements

Subsurface measurements yield valuable data on the downhole performance of a gaslift system. Since a well entry by wireline is not without operational risk, the proposals for downhole measurements need to be properly justified, and detailed programmes should be written to avoid confusion or mistakes.

6.1.3.1. Down Hole Pressure Surveys

Sub-surface pressure measurements are the best and most widely used method to analyse gaslift installations. Surveys can be taken both under static and flowing conditions.

Static pressure surveys will determine:

- static fluid level,
- static gradient(s),
- static bottom hole pressure.

All these data are required to carry out or confirm gaslift design and to monitor trends that may affect gaslift performance.

Flowing pressure surveys are conducted to:

- locate the point of gas injection,
- locate leaks in the tubing, valves or mandrels,
- diagnose multi point injection,
- measure flowing gradient above and below the point of injection and
- measure flowing bottom hole pressure

In combination with representative well tests (preferably undertaken during the pressure survey), flowing pressure surveys will give an indication of inflow performance. If a build-up is carried out, the reservoir pressure and productivity index can be determined. These are essential parameters for gaslift design - particularly for high PI wells where mandrel spacing is critical, for gas lift optimisation (chapter 7) and quantifying the benefits of various improvements to the gas lift system. Skin analyses can only be done if wellbore storage effects are not dominating, or with the use of a downhole shut-in tool.

Flowing surveys can only be successfully run if the well is producing under reasonably stable conditions. If the well is heading violently, an attempt should first be made to stabilise the well by changing production/injection parameters. If a well is in the slug flow regime at surface (which is often mistakenly diagnosed as heading), downhole flowing pressure measurement can often yield reasonable results in those parts of the well where other flow regimes exists. Flowing surveys are conducted at "stations" more or less evenly spread over the tubing with emphasis on the prime area of investigation (for example just below mandrels). The pressure gauge is held stationary at these stations for a certain period (generally 10 minutes to 1/2 hr) depending on tool resolution.

6.1.3.2. Sub Surface Temperature Recording

Temperature surveys can be very useful, and should be run whenever possible in combination with a pressure survey.

Static temperature recordings will provide:

- Geo-thermal gradient.
- Reservoir temperature.

Both parameters are needed to reconcile volumes during gaslift design calculations.

Flowing temperature surveys can give additional information, particularly if the pressure gauge fails to show reliable results. This information includes:

- location of operating valve.
- leaking valves, mandrels or leaks in the tubing.

The cooling effect of expanding gas can be detected fairly easily (except in very high flow rate wells).

6.1.4. Production Logging

Production logging is expensive and should only be considered if all the above methods do not give the required information to enable analysis of the system. Production logs can provide good results, and will allow a detailed investigation of a gaslift string. A further discussion on production logging and details of the tools used can be found in EP 93-1585 "Production Logging Guidelines" [ref. 23].

6.1.5. Data Gathering Frequency

To provide universal guidelines on data gathering frequency is difficult as this depends to a large extent on the operation, the environment and the available resources. In general, the following approach is recommended based on two different operating periods.

6.1.5.1. Data Gathering Immediately After Installation of Gaslift.

The objective of the initial data gathering programme is to verify that the gaslift performance is as per design, and to allow for further performance optimisation. The initial data gathering should take place as soon as possible after installation - preferably within two weeks to a month after start of production. It is important to optimise a gaslift system from the outset. Once satisfactory conditions are met, this data will be used as future reference and trend analyses can start.

Initial data gathering should include:

- a flowing pressure/temperature survey.
- an initial representative well test.
- surface pressure recording (continuous) to monitor injection pressure, tubing pressure and pressure differential across surface choke.
- surface temperature recordings (ambient, injection gas, well head and separator temperatures).

6.1.5.2. Routine Gaslift Operations

During routine gaslift operations, data gathering frequency should be minimised, but should still be sufficient to maintain control over the system, and to pick up any obvious problems. Surface measurement should be taken regularly and serve as performance indicators of the system.

The table below gives a guideline on data gathering frequency;

Type of data gathering	Recommended frequency		Remarks
	Initial	Routine Gaslift	
Visual observations	Yes	Every 3 - 5 days	Routine checks
Surface pressure recording	Yes	Continuous (3)	See notes
Gas measurement	Yes	Continuous (3)	See notes
Surface temperature recording	Yes	Every few days	
Well testing	Yes	At least once a month	As per EP Production Programming guidelines.
Down hole pressure surveys; flowing	Yes	Once every 1 -1.5 years	Depending on No. of wells
Down hole pressure surveys; static	N.E.[1]	If problems or for re-design	PI determination required for re-design, optimisation
Down hole temperature surveys	(2)	(2)	Always run with Pres. Surv.
Production Logging	No	Seldom	

Note: Surface pressure and lift gas injection rate recording should ideally be carried out on a continuous basis using a real time measurement system (such as CAO, SCADA). At the very least, a 3 pen chart recorder should be used.

6.2. Trouble-Shooting

6.2.1. Introduction

Attempting to identify the root cause of a gas-lift problem can be both difficult and exasperating. The surest way to solve such problems is to proceed in a methodical and thorough manner. Haphazard 'quick-fixes' are unlikely to be cost effective in the long term, and can only serve to "bridge" the time required for redesign and/or preparation of a workover (and to obtain production performance data). Correct diagnosis will enable a realistic cost-benefit to be assigned to each workover or wireline entry prospect.

Fundamental to the understanding of gaslift related problems is that the system is intended to operate with a stable supply of dry lift gas at near constant rate and pressure. All other aspects of the gaslift system, including the gaslift valves, tubulars, wellheads, flowlines and separation and treating facilities, are intended to be adequate in capacity, and stable in operation. If one or more of the system components is not working as intended, problems can arise. From a diagnostic point of view, it is important to understand that the non conformance of one component often causes a series of events and process upsets which can often mask the root cause of the problem.

Typical gaslift operating problems are:

---

[1]Not essential

2 Always run temperature surveys in conjunction with pressure surveys.

3 Pressure recording by 3-pen chart recorders.

- Unable to inject gas.
- Unable to kick-off the well.
- Low production.
- The gas-liquid ratio is too low or too high compared to the design. "Under" or "Over" lifting.
- Injection and production pressures and rates are fluctuating (heading).

The following brief guidelines set out a methodology for both new and existing completions, and should be read in conjunction with the design sections of this manual (section 4). The trouble-shooting guidelines cover individual wells only. For total system optimisation refer to chapter 7. Gaslift operating problems and recommended corrective action is discussed in more detail in section 6.2.3. The reports listed in the **Further Reading** section (6.2.4) examine in more detail many of the problems discussed below.

6.2.2. Diagnostic Approach

When trying to analyse a gaslift related problem, a thorough understanding of the gaslift principles is essential, in combination with an appreciation of the operating environment - including the process parameters in which the system is operating. Diagnosis of gaslift problems without a proper database containing elementary data, discussed in section 6.1 above, will result in guesswork - and will most likely be ineffective. Routine or automated data gathering at appropriate time intervals will pay off, not only for normal production optimisation, but will also allow for predictive, preventive, and diagnostic analyses.

Since the Production Operators in the field are dealing with the well and with the system as a whole, they normally develop a "feel" for the system. Therefore, suggestions and experience from Operators are usually very valuable in pinpointing the source of a problem.

The following provides an outline of a systematic approach which can be used to diagnose gaslift related problems in a particular well.

① Collect all the available data for the well(s) in question such as:

- 3-pen recorder charts (injection and producing pressures, gas injection rate)
- Original completion diagram, plus full details of subsequent workovers.
- The current gaslift design, and associated assumptions.
- Flowing and temperature surveys.
- Produced fluid composition.
- Waxing or scaling tendencies. Sand production.
- Estimates or measurements of current PI's and reservoir pressures.
- Field operator opinion and experience for the well under review.

If a significant proportion of the above information is not available, it is difficult (if not impossible) to understand or solve the problem.

② A new gas-lift calculation should be performed using the latest information. It is quite likely that a design will become outdated due to unforeseen circumstances or changes in reservoir performance. Depending on the results, prediction of the actual problem may now already be possible and correction(s) can be proposed. By manipulating (for example) the injection rate, or changing valves, it may be possible to avoid a full workover. The Windows based GLUE program has been specifically designed to assist in this type of diagnostic analysis.

③ If the problem is still unresolved, then data and/or assumptions are probably incorrect. This could be due to a number of reasons, which may not be immediately apparent:

- Check the completion/workover reports for consistency. Are the valves where they are supposed to be?
- There may be a leak in the tubing, casing or valve(s).
- Valves are jammed open, plugged, or they are incorrectly set. They may have been installed in the wrong sequence.
- The PI is over or under estimated.
- Test data may be wrong.

The following section on typical gaslift problems may give some guidance.

Never consider a well in isolation, but also consider the performance of all the other wells in a group. If a particular clusters of wells are affected, then it is likely that a general surface problem or even a reservoir problem exists.

6.2.3. Typical Gaslift Problems/Trouble Shooting

Some typical gaslift problems and symptoms are summarised in table 6.2.1, along with a diagnostic approach and recommended actions . It should be understood that failure of a part of the system very often results in "knock on" effects masking the real cause of the problem. Therefore the table below may be too simplistic for a range of symptoms and should be used as an indication checklist only.

PROBLEM/CAUSE	SYMPTOMS				ANALYSES	CORR. ACTION
	Qinj. (1)	p-inj (2)	p-tub. (3)	Qgross (4)		
LEAKING CASING	HIGH	LOW	LOW	LOW	P-TEST	WORK-OVER
LEAKING TUBING	HIGH	LOW	HIGH	LOW	PLT/AMERADA	WORK-OVER
LEAKING VALVES	HIGH	LOW	HIGH	LOW	PLT/AMERADA	ROCK/CIRCULATE/REPLACE VALVES
LEAKING MANDRELS	HIGH	LOW	HIGH	LOW	P-TEST	WORK-OVER
LEAKING PACKERS	HIGH/ ERRATIC	ERRATIC	ERRATIC	ERRATIC	P-TEST ANNULUS	WORK-OVER
LEAKING X-MAS TREE	HIGH	LOW	LOW	LOW	VISUAL TEST	WORK-OVER
HYDRATE FORMATION	LOW	HIGH	LOW	LOW	CHECK SURFACE PRESSURES	HEAT, HYDRATE INHIBITION
PRODUCTION HEADING	HIGH	NORMAL	ERRATIC	ERRATIC	VISUAL TESTS, PI DETERMINATION	SOLVE CASING HEADING, STIMULATE WELL, REDUCE TUBING SIZE/WORK-OVER
INJECTION HEADING	ERRATIC	ERRATIC	ERRATIC/ NORMAL	ERRATIC	VISUAL TESTS, PI DETER-MINATION, REDESIGN, CHECK FOR LEAKS	REDESIGN, ADJUST RATES
UNLOADING PROBLEMS TOP VALVE	NIL/LOW	HIGH	ERRATIC/ LOW	NIL/LOW	CHECK GRADIENTS, CHECK DESIGN	ROCK UNLOADING VALVE, INCREASE INJ. PRESSURE, CHANGE OUT TOP VALVE
UNLOADING PROBLEMS DEEPER VALVES	HIGH/ NORMAL	HIGH	ERRATIC/ NORM.	LOW	CHECK GRADIENTS, DESIGN, VALVE SETTINGS, WIRELINE REPORTS, PLT IF STABLE PROD.	ROCK VALVES, CIRCULATE CLEAN, CHANGE OUT VALVES, REDESIGN, WORK-OVER?
MULTI POINT LIFTING	HIGH	NORMAL/ LOW	HIGH	LOW/ NORMAL	CHECK GRADIENTS, DESIGN, VALVE SETTINGS, WIRELINE REPORTS, PLT IF STABLE PROD.	ADJUST RATES/PRESSURES, REDESIGN, CHANGE VALVE SETTINGS
UNSTABLE WELL	HIGH	ERRATIC	NORMAL	LOW	LOWING PRESS. SURVEY SURFACE PRESSURE RECORDING	CHANGE GAS RATE, ORIFICE SIZE

(1) Average measured Q injection compared with design injection rate.

(2)&(3) Average recorded injection /tubing head pressure compared with design injection pressure

(4) Average measured gross rate compared to design gross rate. In case of severe heading this may be difficult.

Table 6.2.1. - Typical gaslift problems/symptoms/diagnosis, and possible corrective action.

6.2.3.1. Downhole Leaks

Characterised by higher than expected GLR's to achieve the required flow-rate, thus giving reduced efficiency. Same effect as multi-point lifting.

- *Casing leaks:* due to corrosion, burst or collapse.
- *Tubing leaks:* due to corrosion, sand erosion or damaged couplings.
- *Mandrel leaks:* damaged or eroded.
- *Packer leaking:* Incorrectly set packer, damaged or distorted casing.
- *Valve leaks:* damaged valve seats, incorrect test-rack pressure, jammed open with debris, dome pressure bled off.

The only solution to the first four above is a workover. In order to determine the location of the leak (inside tubing only) it will be necessary to run a temperature survey.

It is possible to clear debris from a valve by 'rocking it': pressure the tubing and casing above the valve opening pressure, and then rapidly bleed off the tubing - this creates a large drawdown across the valve, removing debris.

If this does not cure the problem, then bleed off all the pressure. This will allow the valve to fully seat - crushing any debris. Then repeat the 'rocking' operation.

6.2.3.2. Surface Leaks and Freezing

It is important to check that the injection pressure and rate used for a calculation is representative of the real situation. Wells have been worked-over due to assumed casing pressure-loss, when the real problem was a leaking wellhead connection. A cold or 'sweating' tree may indicate an internal or flange leak. Freezing (hydrate formation) may occur, even in the absence of a choke, due to restrictions in the flowline or wellhead. This further reduces available pressure, and can lead to complete plugging. Thorough dehydration of lift gas will prevent this problem (7 ppm of liquids is a recommended maximum). A correlation between ambient temperature versus hydrate formation, based on historical data, can provide the basis for preventive maintenance.

6.2.3.3. Instrument Malfunction

Instruments can fail or lose calibration. It would be a wise precaution before embarking on remedial work to ensure that the wellhead and production data are accurate.

If functional instrumentation is not available, the problem may not be detected in the first place. In the past, it was recommended that monthly well tests were sufficient for monitoring purposes, it is now felt that consideration should be given to real-time monitoring systems (i.e. SCADA, CAO). The cost of installation of such systems will easily be offset by:

- Higher production due to more rapid corrective action (i.e. less deferment in case of malfunction).
- More efficient allocation of available lift-gas.
- Better ranking of workover schedules
- More efficient field/well start up.

6.2.3.4. Heading

"Heading" is a widely-used term to describe instability in a well on continuous flow gas lift. This should not be confused with slug flow which may exist towards the top of the tubing string. Slug flow is characterised by re-occurring systematic cyclical changes, generally of low severity. Heading on the other hand is featured by sometimes violent surges in THP caused by instability. True heading conditions are **always** harmful, resulting in:

- Excessive use of lift gas (e.g. higher GLR's and power consumption).
- Multi-point lifting, causing unloading valves to cycle open and closed.
- Loss of production due to fluctuating BHP's.
- Upset fluid-handling systems due to large rate and pressure surges.

- Causing other wells on the same system to become unstable.
- Damage to the wellbore, sand control equipment, etc. - due to rapidly changing and/or high drawdowns.
- Inability to perform any form of field or well optimisation.

There are two discernible types of heading - production (tubing) heading, and injection (casing) heading. These two states may exist together or separately but one often results in the other. It is important to differentiate between the two in order to understand the root cause of the problem.

Production Heading:

The well may exhibit small oscillations in rate and tubing pressure, degenerating to the situation where intermittent slugs are produced violently at high rate and pressure. This generally occurs when the production rate of the well is too low for continuous flow and/or the tubing is too large. It may also be caused by upsets in surface facilities, and is often a consequence of injection heading. With large changes in downhole pressures, valve cycling/damage will become an immediate problem. Severe production heading can induce injection heading - even in wells with IPO valves (due to throttling effects).

Some corrective steps for production heading are:

- If there is injection heading, then try to fix that first. Injection heading is more often the root cause of a problem.
- If there is no injection heading, then optimising the tubing size by means of a workover may be the best approach.
- Injecting more gas can solve the problem, but the economic implications of this need to be carefully addressed.
- Choke back the well as a last resort, as this simply loses production. It may be better to live with the problem than accept a reduced production rate.

Injection Heading:

This generally occurs when the gas lift system (operating valve, unloading valves, downhole orifice, surface injection) no longer suits the current situation. Common causes are incorrect injection depth, too low injection pressure and rate, valve spacing too close to cope with small variations in pressure, downhole orifice too big, possibly as a result of it being cutout, fluctuations in gas availability and inherent instability (see section 4.8). The only certain cure for injection heading is good design. In order to satisfactorily re-design the well, you need accurate data. Therefore:

- Determine the primary cause of the instability by adjusting flowrates and pressures.
- Check for leaking valves, tubing etc.
- Try to determine the actual PI of the well.
- Eliminate external interference from the production and injection system.

If it is decided that more gas is required, the valve spacing and opening pressures will probably have to be redesigned. If dummy mandrels have been installed (which is a good practice to increase flexibility) attempt to redesign the gaslift string utilising the dummy mandrels. The Windows GLUE package has been specifically designed to allow this type of calculation to be carried out,

- Use an orifice valve at injection depth. This eliminates the "throttling" effect of normal valves - which is a major cause of injection heading. A higher injection point may be required to ensure sufficient pressure differential across the orifice. Note that the API minimum recommended pressure differential is 100 psi across an orifice or valve, at the deepest point of lift.

- In the same vein: valves with over-large ports should have chokes installed to increase the pressure-drop across them. Larger differential pressures promote critical flow and hence isolate the tubing from casing pressure fluctuations to some extent.
- PPO valves are vulnerable to fluctuations in production pressures. Changes in gas injection can easily lead to the opening of upper valves - and thus multipoint lifting. In this case it may be worthwhile to gain stability at the cost of a less-deep injection point or by installing injection pressure operated valves.

6.2.3.5. Inherent Instability. (See also section 4.7 "Gas Lift Well Stability".)

A system is stable if a small fluctuation in (say) tubing pressure results in an opposite, counterbalancing force which tends to reduce its effect. This is negative feedback. Most naturally flowing wells are in this category since their performance depends on only two opposing, stable (over a short period), controls - inflow performance and tubing/choke characteristics. If you add a third variable (pressure-dependant GLR) to the vertical lift performance, then it is quite easy to get into a positive-feedback situation where small changes are exaggerated and the well becomes unstable.

Asheim's simple criteria [ref. 21] can be used to predict the stability of wells undergoing tubing-pressure fluctuations. He identifies two distinct criteria, either of which will promote stability:

Inflow Response.

When THP decreases, it results in increased liquid flow from the reservoir, and increased gas from the casing. If the GLR in the tubing decreases as a result of this (reservoir response is greater than lift response), then the bottom-hole pressure rises and flow is retarded - thus the system is stable. On the other hand, if the GLR rises due to low reservoir response, the gas flow rate will increase (positive feedback) - leading to instability, heading etc. The equation below indicates that stability is promoted by high PI's, small orifices and high injection rates.

$$F_1 = \frac{\rho_{gsc} B_g q_{gsc}^2}{q_{Lsc}} \cdot \frac{PI}{(EA_i)^2}$$

$$F_1 > 1 \text{ for stability}$$

where:

F_1	=	Stability criteria	
ρ_{gsc}	=	Lift gas density at standard surface conditions	kg/m^3
B_g	=	FVF of gas at injection point	
q_{gsc}	=	Flow rate of gaslift at standard conditions	m^3/s
q_{Lsc}	=	Flow rate of liquids at standard conditions	m^3/s
PI	=	Productivity index	m^3/s Pa
E	=	Orifice efficiency factor	0.9
A_i	=	Injection port/orifice size	m^2

Figure 6.1. below shows a typical gaslift performance curve for a sub-hydrostatic well. Indicated is the gaslift operating envelope which has a maximum at the technical optimum and a minimum as indicated in the figure. The minimum gas injection rate is determined by the inflow response as dictated by the formula above. For lift gas injection below this rate, gaslift will be inherently unstable. From a control point of view it is important to understand this concept as gas allocation

tables should include minimum allowable gas injection rates and should not dictate injection rates in the area of inherent instability (see section 7.2).

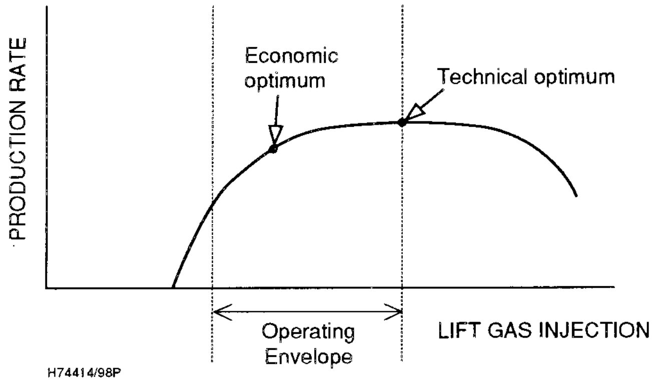


Figure 6.1. - Operating range of a gas lift well.

Casing pressure-depletion response. If the first criteria is not fulfilled, a decrease in the tubing pressure will cause the gas flow-rate to increase more than the liquid flow-rate. This will cause a decreasing tubing pressure, but also depletes the casing pressure. If the casing pressure depletes faster than the tubing pressure, then the injection rate will fall, decreasing the GLR - and thus tend to stabilise the flow-rate. Thus, in addition to the above, a small annular volume promotes stability.

$$F_2 = \frac{V_t p_t \left(q_{fi} + q_{gi}\right)}{V_c g D \left(\rho_{fi} - \rho_{gi}\right) q_{fi} \left(1 - F_1\right)}$$

$F_2 >$ for stability

where:

F_1	=	Stability criteria	
F_2	=	Stability criteria	
V_t	=	Tubing volume downstream of gas injection point	m^3
p_t	=	Tubing pressure	Pa
V_c	=	Gas conduit volume	m^3
g	=	Acceleration of gravity	m/s^2
D	=	Vertical depth to injection point	m
ρ_{fi}	=	Reservoir fluid density at injection point	kg/m^3
ρ_{gi}	=	Lift gas density at the injection point	kg/m^3
q_{fi}	=	Flow rate of reservoir fluids at injection point	m^3/s
q_{gi}	=	Flow rate of lift gas at injection point	m^3/s

Gas lift stability criteria should be considered during the design stage (see section 4.3). It is often wise to run sensitivities on the least accurate input parameters to confirm that the gaslift design is sufficiently flexible. Remember that the well will need to be designed to operate over a range of lift gas injection rates. Therefore an operating range or "turndown"for the well should be defined at the design stage and clearly noted.

6.2.3.6. Flow Chart for Solving Gaslift Problems

Figure 6.3 (fold out) provides a schematic approach that may be used in solving gaslift related problems. Although a useful aid to gaslift problem solving, every step should be considered with an open mind as it may be possible that a situation exists in the well under consideration which can not be "caught" by the decision tree approach. Also multiple problems can exist in a well which requires several loops through the decision tree solving one problem after the other prior to finally solving the overall problem. The decision tree should be used if steps 1 & 2 (section 6.2 above) have not been successful in solving the problem.

Decision Tree Logic

The flowchart is based on the assumption that a problematic gaslift well should, if possible, be produced for sufficient time at a stable (and constant rate) to allow for data gathering by means of a PLT or an Amerada pressure/temperature survey. The data obtained will then be used for a re-design and/or evaluation of the well integrity (leaks). Adjustment of gaslift variables and/or valve settings is the logical next step to obtain acceptable production rates and conditions. Verification of achievement of design conditions should be carried out to gain confidence on the control of the system. Following actual system adjustment with the aim of optimisation, a feedback loop should be considered to confirm that the earlier results such as production stability and rate are not jeopardised. Only as a last resort should a workover be considered - and certainly not before the cause of the gaslift problem is fully understood. While awaiting a workover it can often be beneficial to change the valve configuration and settings in a well such that sub-optimal (often shallower) gaslift at more or less stable rates is possible. Figure 6.2 summarises the above mentioned approach.

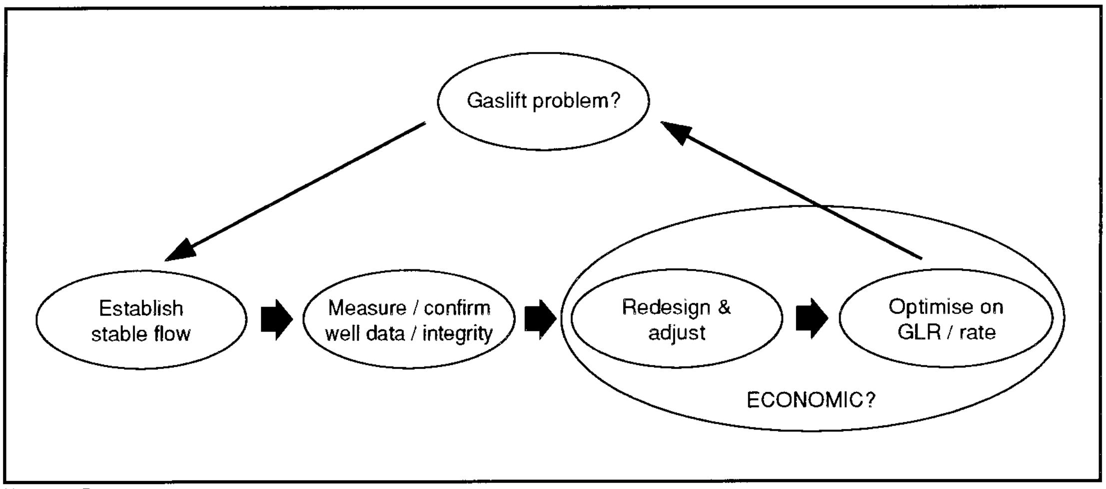


Figure 6.2. - Uderlying Philosophy of gas lift problem solving flow chart.

The above suggested approach can be captured by consecutively considering the following questions:

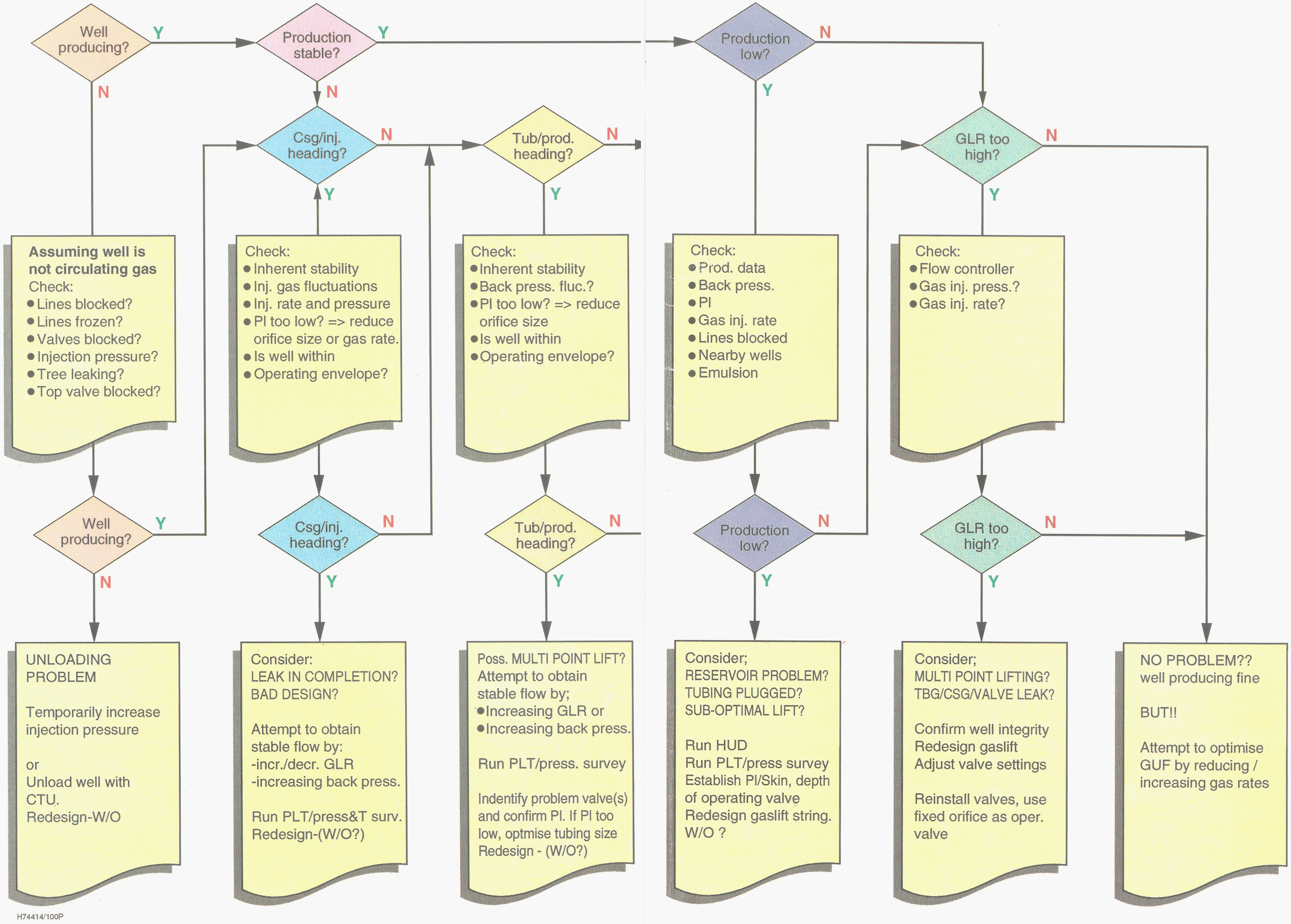
- Is the well producing?
- Is production stable?
- Is production rate as expected?
- Is gas consumption as expected?
- Is the gaslift system fully optimised?

For each possible problem area, a corrective approach is suggested. It is realised that the above method is basic and crude, but it is believed that it gives the basis for an approach to gaslift problem solving which will result in effective and appropriate corrective action. Comments on the approach are welcome.

6.2.4. Further Reading:

1. API, "Gas Lift (Voc training series 6)", Chapter 9.[12]
2. API, RP-11V8, "Rec Practice for Gas-Lift Systems. (Draft)", Publishing date in 1994 [14]
3. Brown, Kermit E., "The Technology of Artificial Lift (Vol 2a).", Pages 355-444 [4]
4. Winkler, Dr. H.W. "CAMCO Gas Lift Manual.", 11.01-11.24 [24]
5. Harald Asheim, "Journal of Petroleum Technology", November 1988 p.1452-4. [21]
6. SSB, "Quality Improvement in Gas Lift Optimisation.", October 1992. EP 93-1792. [18]
7. PDO, "Gas Lift Optimisation QIP.", December 1992. EP 93-1791. [25]

GAS LIFT TROUBLESHOOTING (Figure 6.3)



7. GAS LIFT OPTIMISATION

7.1. General

The term "optimisation", as applied to gas lift, can refer to several different activities [ref. 18, 25].

Leaving aside the aspects of the mechanical completion and design discussed in the previous chapters, optimisation in a gas lift context generally refers to the optimum distribution of gas to a number of wells based on the premise of maximising oil production or operating cash income. This procedure is discussed in the following pages.

7.2. Individual Well

The typical performance of a gas lifted well is shown in figure 7.1, where it is assumed that the well will not sustain natural flow and requires the injection of a certain minimum volume of lift gas to support flow. This minimum volume of gas is known as the *kick-off requirement*

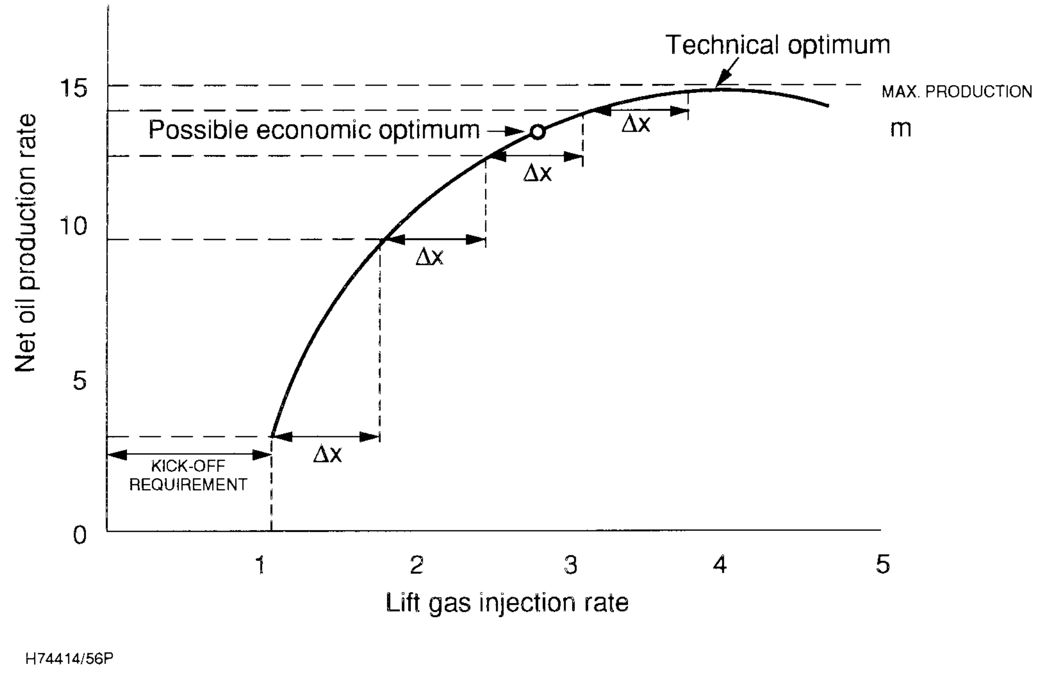


Figure 7.1. - Gas Lift Well Performance Curve.

As the gas injection volume is increased, the production rate of the well increases until the hydrostatic head reduction due to the added gas is balanced by the increase in friction losses due to the greater flow velocity of the produced fluids. At this point the maximum flow rate for that conduit configuration is reached. Increasing the gas injection rate beyond that point causes a decrease in production rate. This point is known as the technical optimum.

It should be noted that the slope of the performance curve gradually decreases to become zero at the maximum and negative thereafter. In other words, after kick-off, increments in gas injection yield progressively smaller increases in production rate. It therefore follows that there will (most probably) be an economic optimum which will be lower than the technical optimum.

The shape of the oil production versus gas injection performance curve is the basis for gas lift optimisation. Wherever possible, the shape of the performance curve should be validated with actual field data. The latest well test point should fall on or close to the curve.

For an individual well, various combinations of the variable parameters can be used to generate gas lift performance curves of the type shown in figure 7.1. Thereafter, an economic evaluation can be performed to select the 'optimum' design for that particular well.(see also the discussion in chapter 4).

In some cases it may be necessary to go through an iteration process to determine the best combination of controllable parameters that will yield the most economic design. An example is the selection of the optimum combination of conduit diameter, surface gas injection pressure and gas injection volume. See figure 7.2.

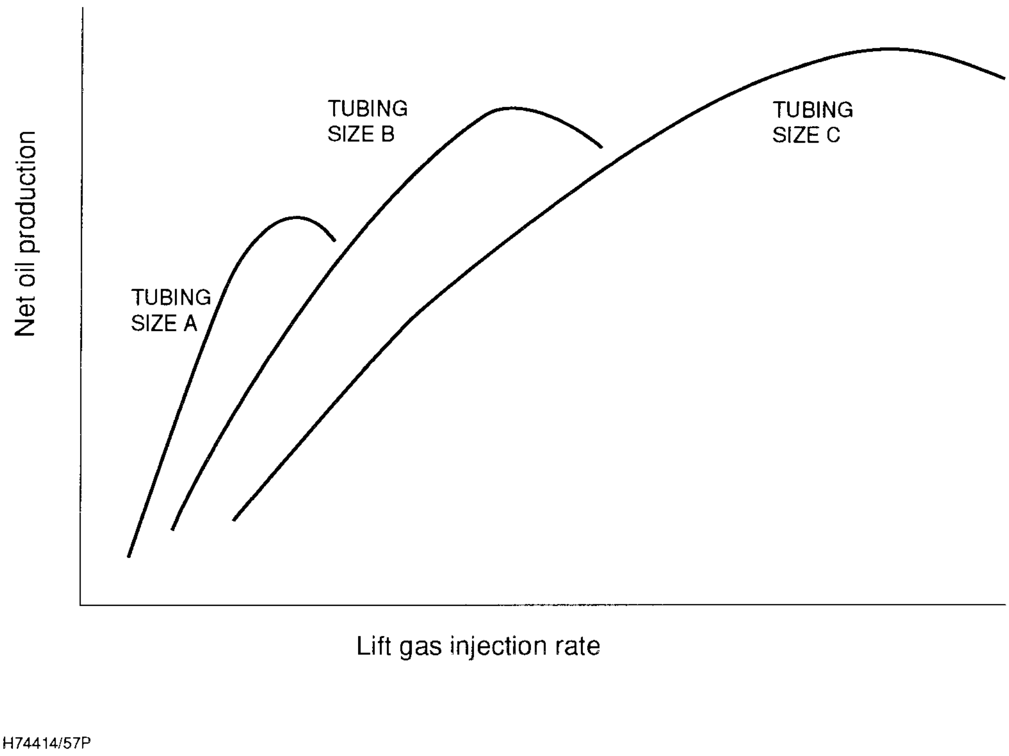


Figure 7.2. - Well performance curves for various tubing sizes.

Two terms frequently used to characterise and compare the performance of gas lifted wells are the Gas Utilisation Factor (GUF) and the incremental or additional GUF. The GUF at any point of the gas performance curve is the ratio of total net oil production divided by the total lift gas volume, i.e. the net oil production per unit of lift gas. The GUF reflects gas lift efficiency and can be used to rank wells in order of priority for lift gas allocation. See figure 7.3.

A high GUF represents an efficient lifting operation with little gas required to lift a large volume of oil. A low GUF indicates low efficiency and generally reflects a well with some combination of low PI, high water cut and/or non-optimum flow conduit. The maximum GUF for a well is determined by drawing the tangent line to the well performance curve through the origin.

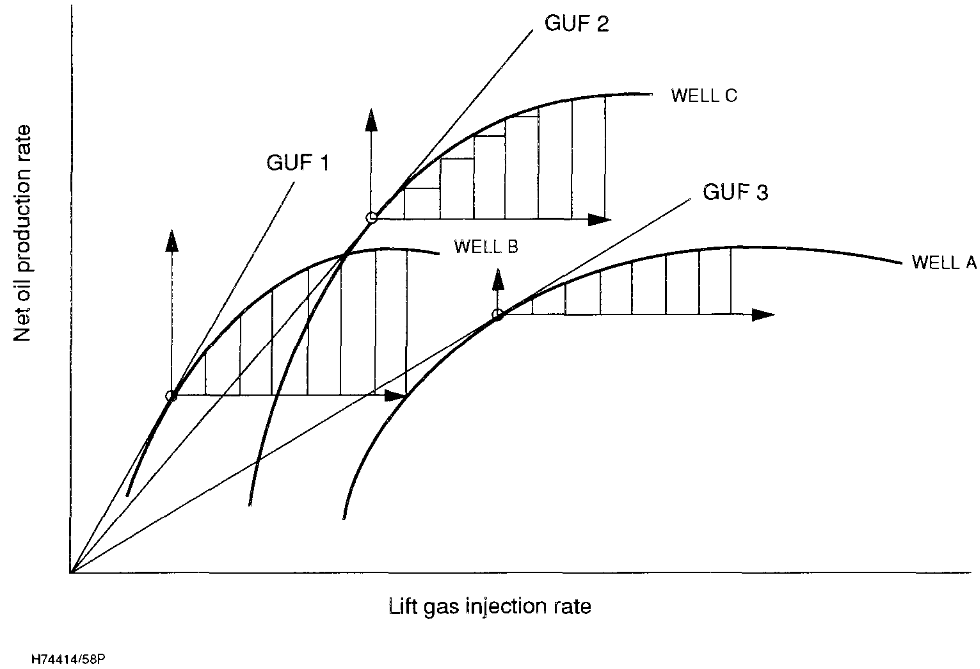


Figure 7.3 - GUF Curves

The **additional** GUF at any point represents the incremental gain in oil production by injecting an additional increment of lift gas. The incremental GUF is more important when considering gas allocation, as it determines the effect on oil production of increasing or decreasing gas injection. As the maximum production point is approached, the additional GUF will decrease to zero.

The gas lift performance curve translated into monetary or economic terms is shown in Figure 7.4. Revenue, in this context, is the income from the produced oil (and in some cases the associated gas). Production costs include the treatment and handling of the produced oil, the compression and processing of the lift gas, and the treatment and disposal of the produced water.

At the point on the cost/revenue curve at which the slope is equal to one, the incremental revenue just balances the incremental cost of production and hence the rate of return (ROR) on the additional investment is zero. This point is the economic limit of gas lift for the well. Normally the lift gas volume would not exceed the volume corresponding to the economic limit but in certain circumstances this may be required to meet short term production targets.

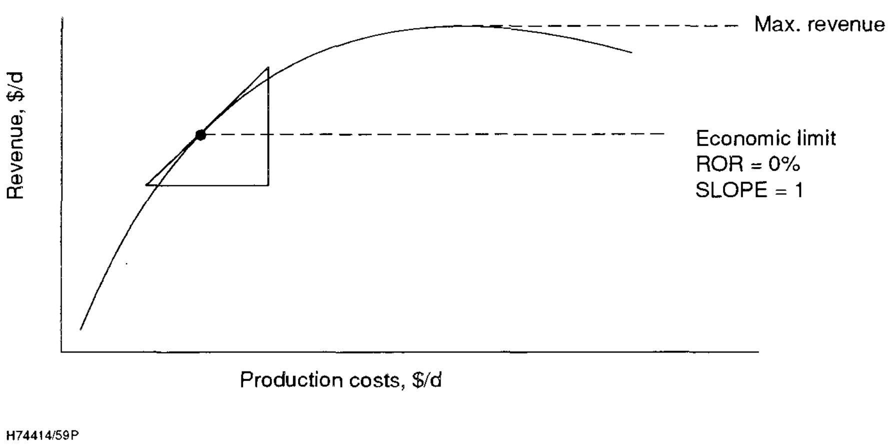


Figure 7.4. - Cost/Revenue Curve.

In general, the optimum lift gas volume for a well should correspond to that point on the economic curve with a rate of return consistent with the company objectives. The next increment of gas lift will not yield sufficient additional revenue to provide a rate of return on the incremental cost.

7.3. Field-Wide Optimisation

The logical procedure is to optimise the design of each individual well, then rank all the wells on the basis of their response to incremental gas injection - and proceed to distribute the available gas so as to obtain maximum benefit.

If the volume of gas available for injection is limited, the individual well optimisation must be carried out with this in mind. i.e. conduit size and gas lift design selection should be limited to suit a realistic maximum rate per well. It would be useless to design a string for optimum GLR if this GLR value is not attainable with the available injection gas, or not likely to be achieved during normal operation.

The distribution of a limited amount of lift gas amongst a number of producing wells has to be made keeping in mind the specific constraints applicable to individual wells, the reservoir and the overall system (each well most probably has different producing characteristics such as PI, water cut, natural GOR, reservoir pressure, crude quality etc.)

Reasons for typical constraints are: reservoir management, sand influx, water and/or gas coning, gas and water disposal, production quotas, export quality requirements, system capacity.

In general, the following two main cases are considered:

1. All wells must be kicked off and produced, regardless of the effect on efficiency. (generally applies for reservoir management reasons)
2. Wells must be kicked off in order of decreasing GUF until all gas has been distributed.(i.e. not *all* wells must be produced). Applies when maximum benefit is the objective.

The optimum lift gas distribution is determined as follows:

Case 1

- The required amount of kick-off gas is allocated to all wells.
- The remaining volume of lift gas is allocated according to the rank of decreasing additional GUF's. Lift gas is first allocated to the well with the highest additional GUF (i.e. with the steepest slope on the well performance curve for a specific gas increment). Lift gas is then allocated to the well with the second highest additional GUF (may be the same well) and so on until the available lift gas is exhausted.

For any well or group of wells the allocation of lift gas may be terminated if a constraint becomes applicable.

Case 2

- Wells are ranked in terms of their maximum GUF.
- The well with the highest maximum GUF is the first well to be kicked-off.
- If the kick-off production rate divided by the kick-off lift gas rate for the next well is greater than the additional GUF of the previous well then gas is allocated to the second well (and the well kicked off). Referring to figure 7.3., well A requires a large kick-off volume. It is better to allocate the lift gas to the other wells until the incremental GUF declines to a point where it is now more beneficial to kick-off well A. Having kicked the well off it may be allocated additional gas as the incremental GUF will initially be high.
- The above procedure is repeated with the next additional GUF's of kicked-off wells being compared with the kick-off requirements of wells not yet kicked-off.

Lift gas is allocated in this manner until all has been used, or until a constraint is met.

For practical purposes, the use of a computer optimisation program such as GASALL or GLUE should be used.

A forecast of net oil production for the well or wells considered should be produced for each alternative considered to enable meaningful evaluation.

7.4. Optimisation Using Computer Assisted Operations (CAO)

The approach outlined in section 7.2.1 will lead to the optimum distribution of lift gas to a group of wells. If there is a significant change in the lift gas availability (e.g. compressor outage) it therefore follows that the same procedure should be applied to arrive at a new optimum distribution of the lift gas to each of the wells. It is however very man-power intensive and time consuming to adjust the surface choke on every well (could be as many as 500 wells) each time there is a compressor outage. Past practices have been to create a “swing list”; ranking wells in order of GUF and closing in individual wells when there is a “shortage” of gas. In this way only a limited number of wells need to be visited. The swing list however does not maximise production for the available gas. Also this technique may involve frequent closing-in (and kick-off) of wells which can lead to early failure of the downhole equipment. Although optimised lift gas distribution was recognised as being the best way to obtain maximum field potential, it was simply not practical in most cases to adjust all the surface chokes on a frequent basis.

Recent developments in control systems, and in particular computer software designed for artificial lift, now mean that the optimised distribution of lift gas on a “real time” basis is possible. Since early 1992 Shell Oil (SOC) and SIPM have been working on a joint project concerning artificial lift CAO.

A major aspect of this project concerns real-time monitoring and control of gas lift systems (known as GLUE/CAO) [ref. 26]. A successful field trial has already been conducted with the system in the Gulf of Mexico, and further trials are planned in PDO for 1994. It is the intention that the hardware/software will be available by mid 1995.

The basic principal of the system is shown below.

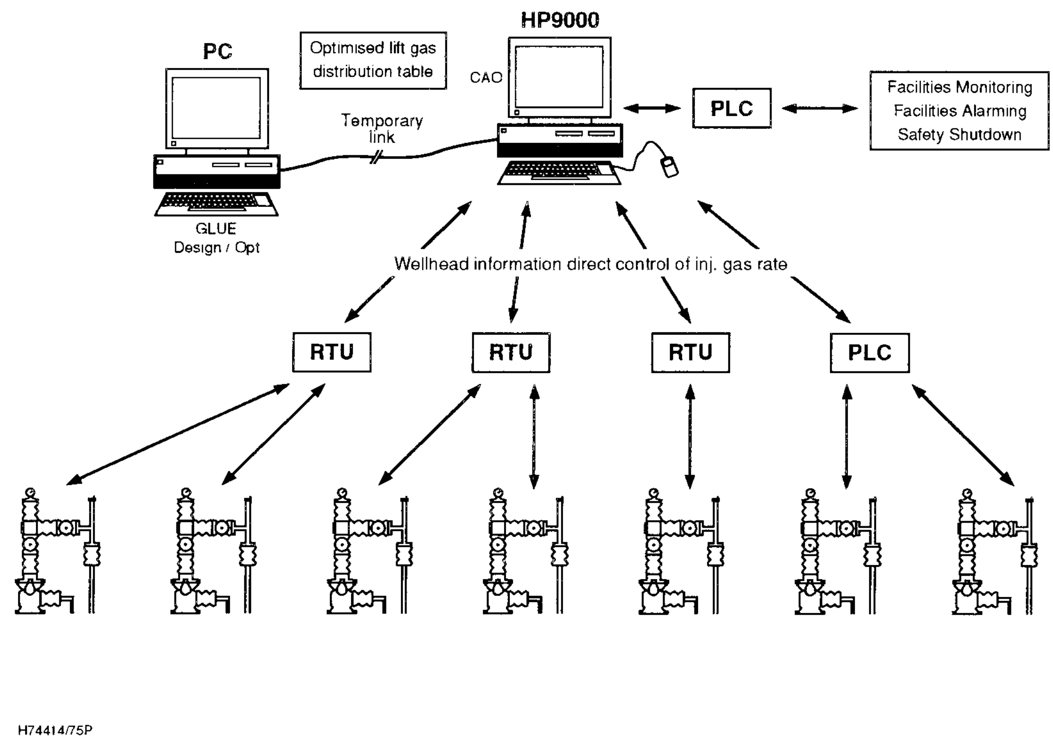
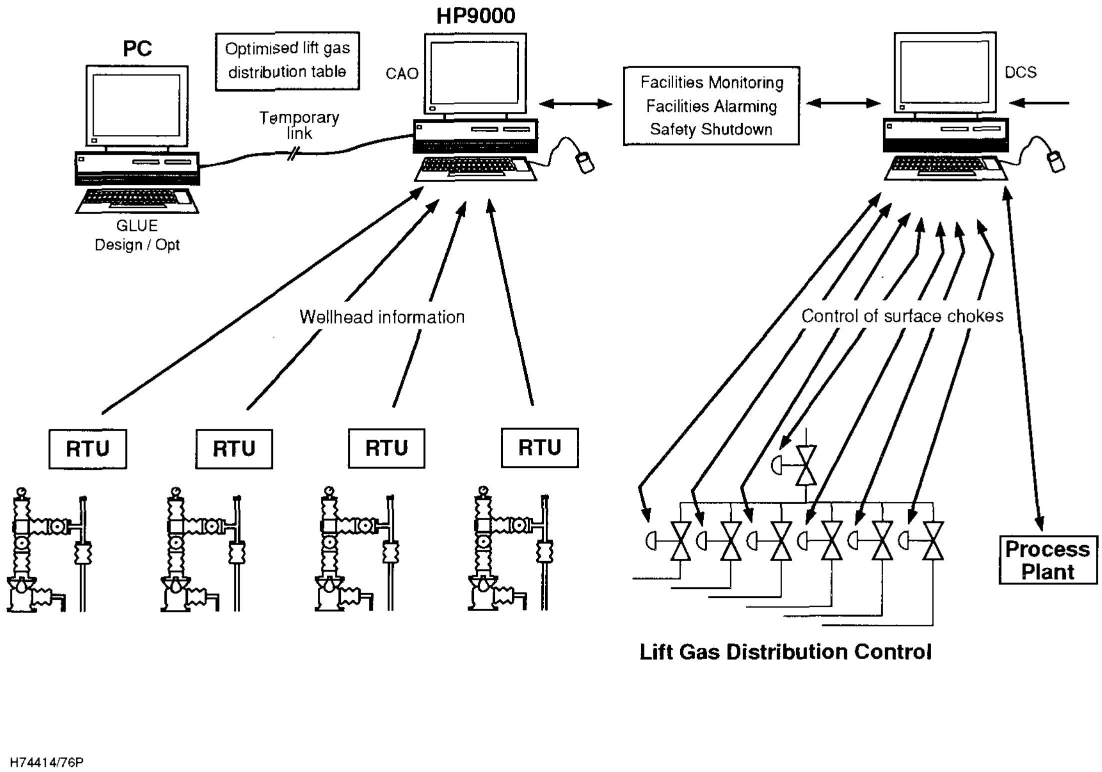


Figure 7.5. - CAO with direct wellhead control of lift gas.



Figures 7.6. - CAO With interface to DCS controlling lift gas distribution.

The basic elements of the system are:

- **GLUE**. Gas Lift Users Environment.

  This programme is designed to perform the multiphase flow calculations required in order to match the flowing/gas lifted well. Well-test and flowing gradient data can also be used by the program to obtain a match of well performance. In addition, the program has a design capability (mandrel spacing, valve set pressures and orifice sizing) which allow a (re)design of the well.

  In the current configuration the main "output" from GLUE from a well-control point of view is the optimised lift gas distribution table. Currently this table is made available to the CAO system via a temporary link. In future it is the intention to install GLUE on the same "box" as the CAO system which will then allow the full diagnostic capabilities of GLUE to be used on a real time basis. It is also the intention that GLUE will allow definition of the well "operating envelopes".

- **CAO control**.

  Two principal configurations are envisaged. Either lift gas is controlled/distributed centrally (figure 7.6.) (as would be the case in an onshore gathering station) or the control is at the wellhead (figure 7.5.) (as would be the case when a "ring main" type of lift gas distribution system is used (e.g. offshore small satellite platforms).

  The control system monitors the total amount of lift gas available. When a significant change in the rate of available gas is detected (depending on a number of pre-set rules i.e. magnitude of reduced volume, time scale of the outage etc.) the system will use the table of optimised lift gas distribution to determine the new set points for the lift gas rate controllers and then re-configure the appropriate wells.

These new lift gas rates are **target rates**. That is to say that feedback from the individual wells (THP, CHP and injection rate) is examined by CAO to ensure that the well is operating in a stable manner within the operating envelope for that well. In this way problems such as holes in tubing, freezing of lift lines, surface choke cut out etc. will be detected early. It is the intention that these conditions are "flagged" to the Operator as an "exception". In this way an Operator can supervise a large number of gas lift wells.

The above system does not represent the "only" way of optimising a lift gas system, however it does provide a way of handling large numbers of wells on a "real time" basis which in some cases can lead to considerably more production over a period of time. See figure 7.6. below.

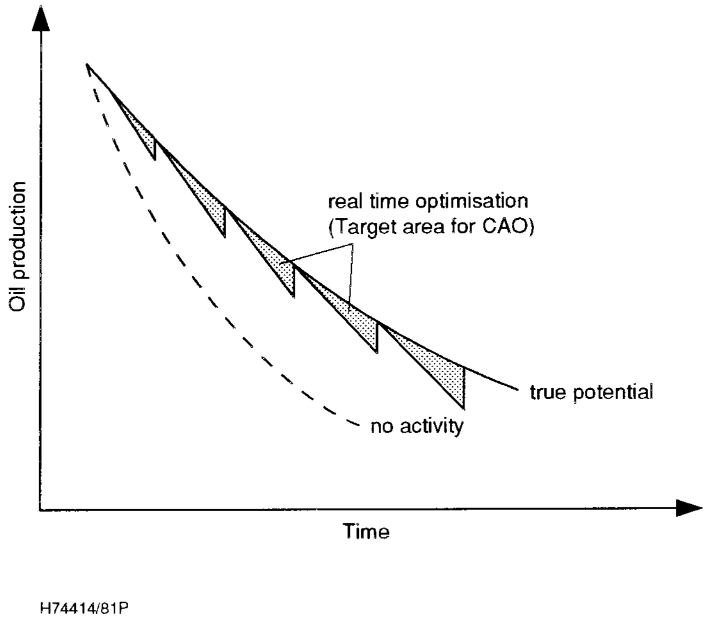


Figure 7.6. - Gas lift system "efficiency" with time.

A APPENDIX A: PRINCIPLES OF WELL PERFORMANCE RE-VISITED

This appendix has been adapted from Group Production Engineering Training Material. It is intended to provide a very brief overview/reminder of the principles of well performance modelling - a fundamental subject in the design of gas lift systems.

A.1. Steady State Inflow Performance

The rate at which fluid will flow towards the wellbore depends upon the nature of the fluid, the type of reservoir rock, and the driving force. This driving force is not the reservoir pressure but the difference in pressure between the reservoir and the wellbore, called the drawdown (P_{DD}).The inflow performance relationship (IPR) quantifies the flow rate from a well as a function of the drawdown. See Figure A.1 below.

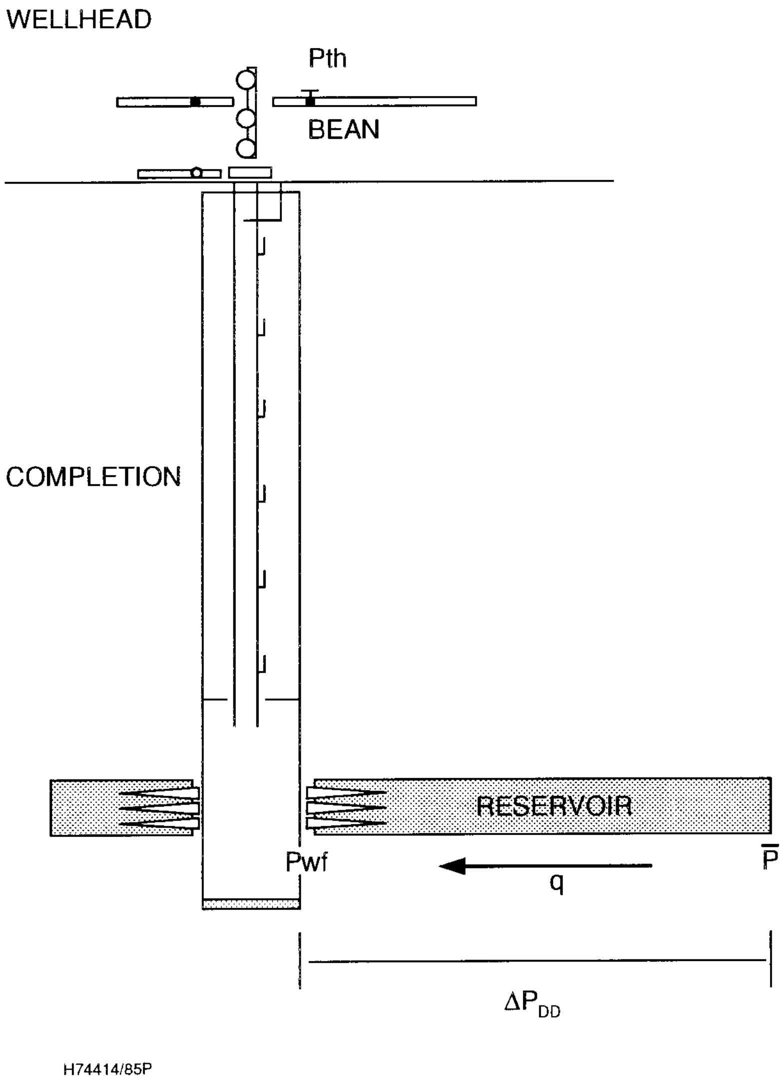


Figure A.1. - Zone of Interest in Inflow Performance

Radial inflow into a well is depicted in Figure A.2 The variation in pressure with radial distance from the well and the pressure at the outer boundary (p_e) depend on the initial and inner and outer boundary conditions.

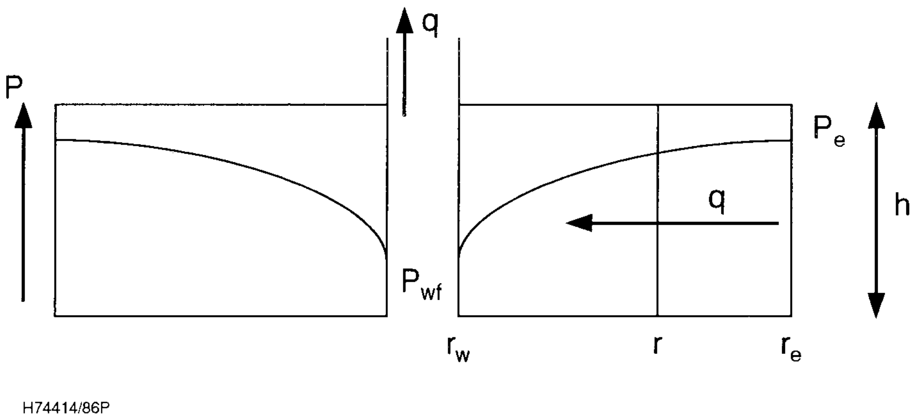


Figure A.2. - Radial Flow of Oil to a Well

Three different flow conditions can be distinguished:

Transient flow:	Applied to well test analysis.
Semi-steady state flow:	Used in well test analysis to investigate reservoir boundaries.
Steady state inflow:	Used to model inflow performance.

A.1.1. Steady State Inflow

Assuming that the reservoir is homogeneous in all reservoir parameters, Darcy's law for the radial flow of a single phase fluid can be expressed as (Figure A.2.):

$$q = \frac{KA}{\mu} \frac{\partial p}{\partial r}$$

where:

q = volumetric flow rate.

K = permeability.

A = cross sectional area of flow.

μ = viscosity.

$\frac{\partial p}{\partial r}$ = radial pressure gradient.

Assuming that the well is completed over the entire reservoir thickness (h), and integrating the above, the radial flow equation can be written:

$$p_e - p_{wf} = \frac{q\mu}{2\pi Kh} \ln\left(\frac{r_e}{r_w}\right)$$

where:

p_e = pressure at the outer boundary of the drainage area.

p_{wf} = flowing bottom hole pressure.

r_e = outer boundary radius.

r_w = wellbore radius.

Since flow rates are reported with reference to standard conditions the formation volume factor (B_o) should be incorporated. Hence, for steady state the radial flow equation becomes:

$$\bar{p} - p_{wf} = \frac{qB_o \mu}{2\pi Kh}\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]$$

The term relating the flow rate to the pressure drop is called the "productivity index", J, so:

$$q = J(\bar{p} - p_{wf}) = J\Delta P_{DD}$$

where:

$$P_{th} > 1.9P_{fl}$$

A.1.2. Straight Line Inflow Performance Relationship

When we consider the parameters in the equation for the productivity index, the following comments can be made:

- r_e and r_w are constant
- μ and B_o are pressure dependent.

However, for single phase flow, which occurs when the flowing pressure is above the bubble point pressure, these last three parameters can be considered constant (independent of pressure). Under these conditions the productivity index is constant and usually given the symbol PI. Hence, the equation:

$$q = J\Delta P_{DD}$$

describes a straight line as depicted in Figure A.3.

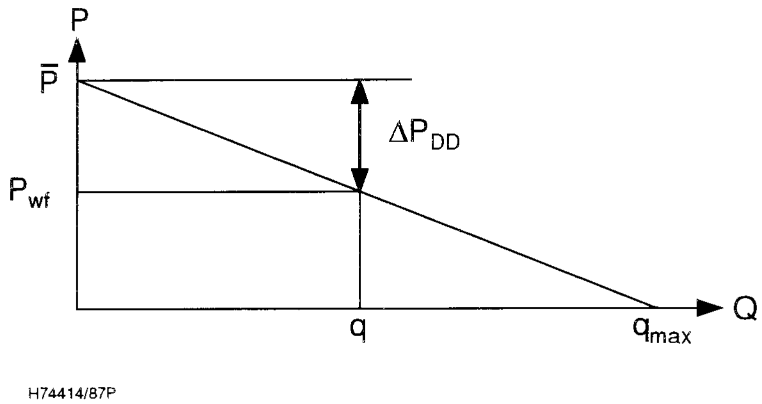


Figure A.3. - Straight Line IPR

A.1.3. Vogel Inflow Performance Relationship

When the flowing bottom hole pressure is below the bubble point pressure, two phase liquid and gas flow occurs in the reservoir, the parameters k, μ, and B_o are no longer constant and hence the linear relationship defined above is no longer valid. This type of behaviour has been observed in solution gas drive reservoirs. As depletion proceeds the productivity of a typical well decreases. Under these conditions, a plot of flowing bottom hole pressure against production rate results in a curved, rather than a straight line and there is a progressive deterioration in the inflow performance relationships as the reservoir is depleted (Figure A.4.).

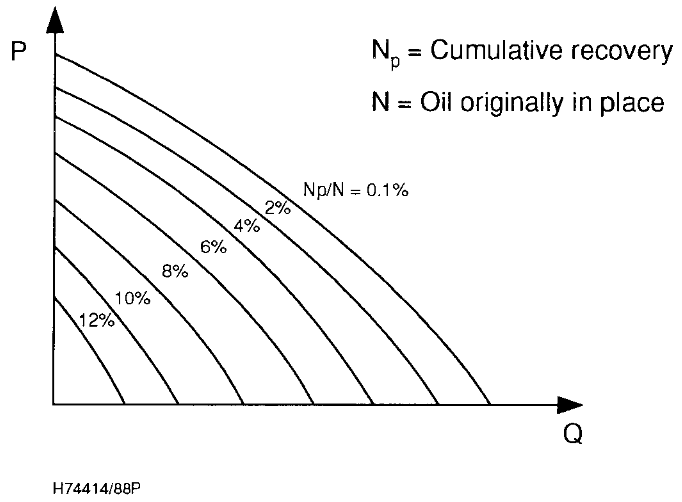


Figure A.4. - IPRs For A Solution Gas Drive Reservoir

The inflow performance relationships shown above may be redefined as non-dimensional IPRs. This is done by expressing the bottom hole flowing pressure as a fraction of the maximum shut-in pressure, and the relevant flow rate as a fraction of the maximum production rate for that curve at that point in time. When this is done, the curves appear to be very similar throughout most of the producing life of the reservoir. The curve giving the best fit to these non-dimensional IPRs is called the reference IPR curve, or the Vogel IPR. This reference curve is shown in Figure A.5.

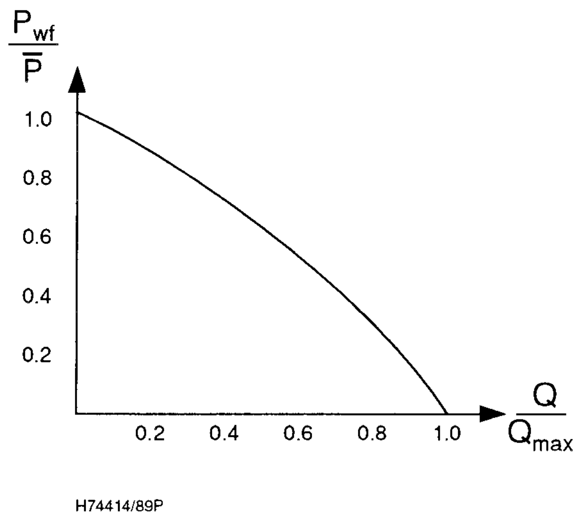


Figure A.5. - Vogel IPR Reference Curve

The equation of the reference curve is:

$$\frac{q}{q_{\max}} = 1.0 - 0.2\frac{p_{wf}}{\overline{p}} - 0.8\left(\frac{p_{wf}}{\overline{p}}\right)^2$$

For comparison to the Vogel IPR, the relationship for a straight line (PI) IPR would be:

$$\frac{q}{q_{\max}} = 1.0 - \frac{p_{wf}}{\bar{p}}$$

A.1.4. IPR for Reservoirs with Static Pressures Above Bubble Point

The IPRs described above dealt with production conditions either above or below bubble point. It may in many cases be more appropriate to define an IPR which is valid for both conditions. Above p_b the IPR will be linear; when the p_{wf} is below p_b, a curved IPR will occur (Figure A.6.).

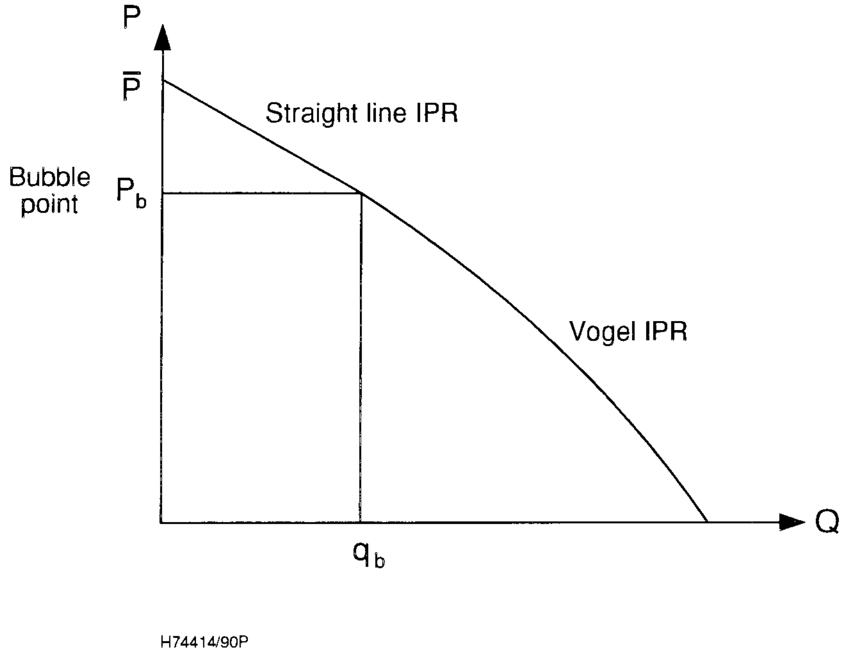


Figure A.6. - IPR for Average Pressure Above Bubble Point

The solution for $p_{wf} < p_b$ is (Vogel/Glass):

$$q = J^* \left[\bar{p} - p_{wf} - \frac{\left(p_b - p_{wf}\right)^2}{2.25 p_b} \right]$$

where J^* productivity index for the straight line part of the IPR

A.1.5. Establishing a Well's IPR

The inflow performance relationship for a given well has to be established by a well test. In theory, one production rate with corresponding bottom hole pressure and the shut-in pressure will define the inflow performance relationship. In practice a number of flow rates may be taken to confirm the well performance. If a sample of formation fluid is taken and analysed to establish the bubble point pressure, it will be possible to decide whether to use the straight line, the Vogel or the Vogel/Glass inflow performance relationship.

A.2. Vertical Flow

The inflow performance relationship allows us to predict the capacity of the reservoir to pass fluids against the prevailing bottom hole conditions. However, the overall ability of a well to produce hydrocarbons to surface depends on both the inflow performance and the vertical flowing pressure

losses. The ability to pass reservoir fluids through the tubulars is termed the "vertical flow performance" and is a function of the physical characteristics of the production conduit and the fluid properties. The ability to predict vertical flow performance for various tubulars is important because in a flowing well the majority of the pressure loss can be attributed to flow in the tubing string. Typically, 75% of all the flowing pressure losses occur in the tubing, so minimising this pressure loss has a large effect in maximising the production rate from the well.

Clearly, inflow and vertical flow are closely related because the end condition of inflow performance is the initial condition of vertical flow. Therefore, the capacity of the reservoir to pass fluid to the wellbore and the capacity of the tubing to pass the fluid to the surface have to be matched, and be operating in equilibrium (Figure. A.7.).

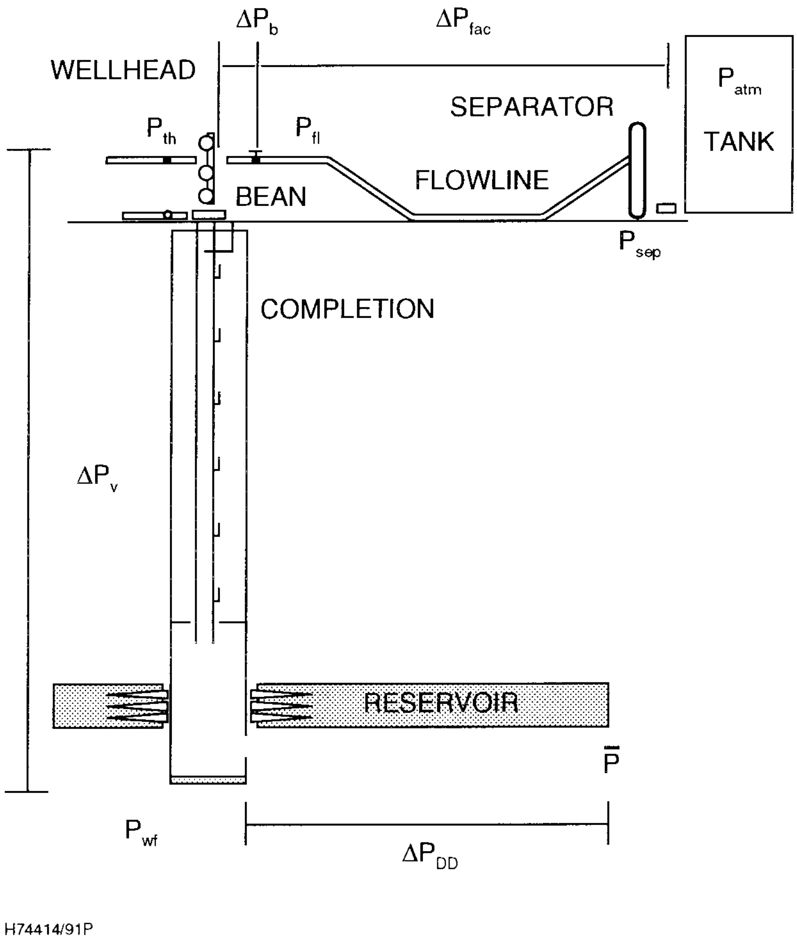


Figure A.7. - Pressure Drops in Oil Production

To develop a full understanding of flowing and gas-lifted wells, it is essential to recognise that there are three distinct sets of conditions affecting the producing well. The first set of conditions affect the flow of fluid into the borehole, the second set affect the flow of fluid to the top of the well, and the third set govern the fluid flow through the surface plant.

A.2.1. Flow Regimes

Petroleum hydrocarbons are volatile substances by nature. During the process of flowing oil from the reservoir to surface, the oil undergoes a large reduction in pressure. During this process, a pressure will be reached when gas is released from solution and there will be two distinct phases (oil and gas) flowing together.

The analysis of vertical flow performance involves establishing a relationship between pressure and depth over a given length of pipe for a variety of conditions. In order to establish this relationship a knowledge of the flow regimes, which exist in two phase flow in the tubing, is vital.

A.2.2. Vertical Flow Equation

The general format for an equation describing the pressure losses in a well may be written as:

Total pressure loss along a tubing length	=	Pressure loss due to elevation	+	Pressure loss due to friction	+	Pressure loss due to acceleration

$$\frac{dp}{dh} = \rho\, g \cos\theta + \frac{fpv^2}{2d} + pv\frac{dv}{dh}$$

where:

ρ = density of the fluid

θ = inclination of the tubing

f = friction factor

v = velocity of fluid

d = diameter of tubing

h = length of tubing

In a flowing well, both the density of the fluid and the volume of the fluid are a function of pressure. The above equation is therefore implicit in pressure and can only be solved by iteration, with the aid of computer programs, or by using empirical correlation's.

A.2.3. Gradient Curves

Gradient curves are based on the observed pressure behaviour in flowing wells, and recognise seven primary quantities, as listed below:

- Production rate Q
- Gas liquid ratio GLR
- Water cut BS&W
- Tubing diameter d
- Tubing length L
- Tubing head pressure P_{th}
- Tubing intake pressure P_{wf}

When any six of these parameters are known or assumed, the seventh can be found by using the appropriate set of gradient curves. This shown in Figure A.8 in which some assumed conditions are stated, so for a fixed tubing head pressure the intake pressure can be found.

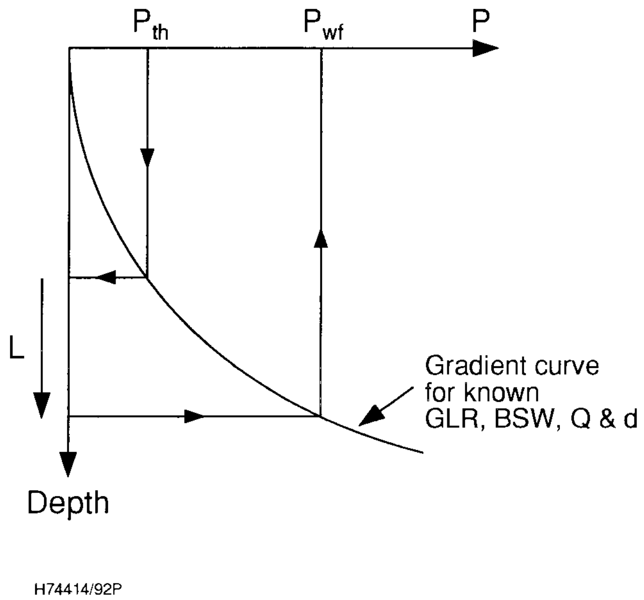


Figure A.8. - Gradient Curve

The Nature of Two Phase Flow

It is worth briefly describing the way in which liquid and gas flow together in a tubing in order to gain an insight into the nature of the flowing well. The nature of two phase flow is largely the result of the interaction between two phenomena:

- The resistance to the flow of fluid
- The slippage of gas through the fluid

The pressure in a column of liquid and gas is due to the weight of the mixture, which increases with decreasing gas/liquid ratios. However, it is less obvious that for any gas/liquid ratio and depth there is a flow rate through the tubing that requires a minimum lifting pressure, with lower flow rates requiring more lifting pressure due to slippage and higher flow rates requiring more lifting pressure due to resistance. Also, for given flow rates, it is true that a small quantity of gas is effective in substantially reducing the bottom hole pressure. The interaction between these parameters is described in the following paragraphs.

Consider a length of tubing standing vertically with the upper end open to the atmosphere (Figure. A.9.). At the lower end of the tubing liquid is introduced at a low rate. This liquid flow rate will be kept constant for all the conditions described below, during which time gas will be introduced into the tubing in gradually increasing quantities.

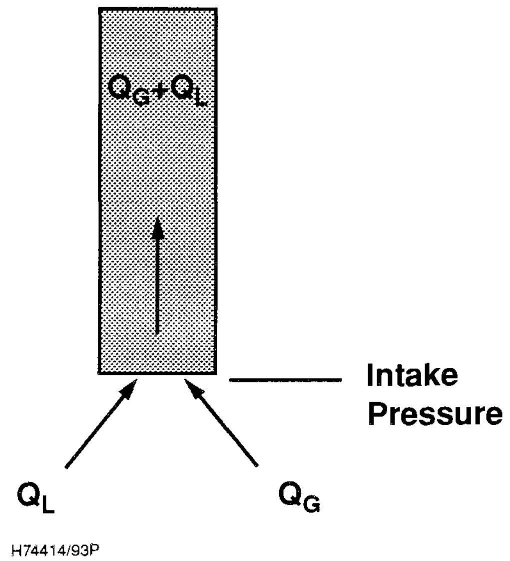


Figure A.9. - Vertical Flow of Liquid and Gas

Plotting the intake pressure against the GLR shows that the intake pressure is initially reduced by increasing the GLR (Figure. A.10.). This effect becomes less significant with increasing GLR and a minimum intake pressure can be seen. Increasing the GLR above this minimum value causes the intake pressure to rise. This is because the total mass of liquid and gas being forced through the tubing is very high, with the result that flow velocities and hence frictional flowing losses are now significant.

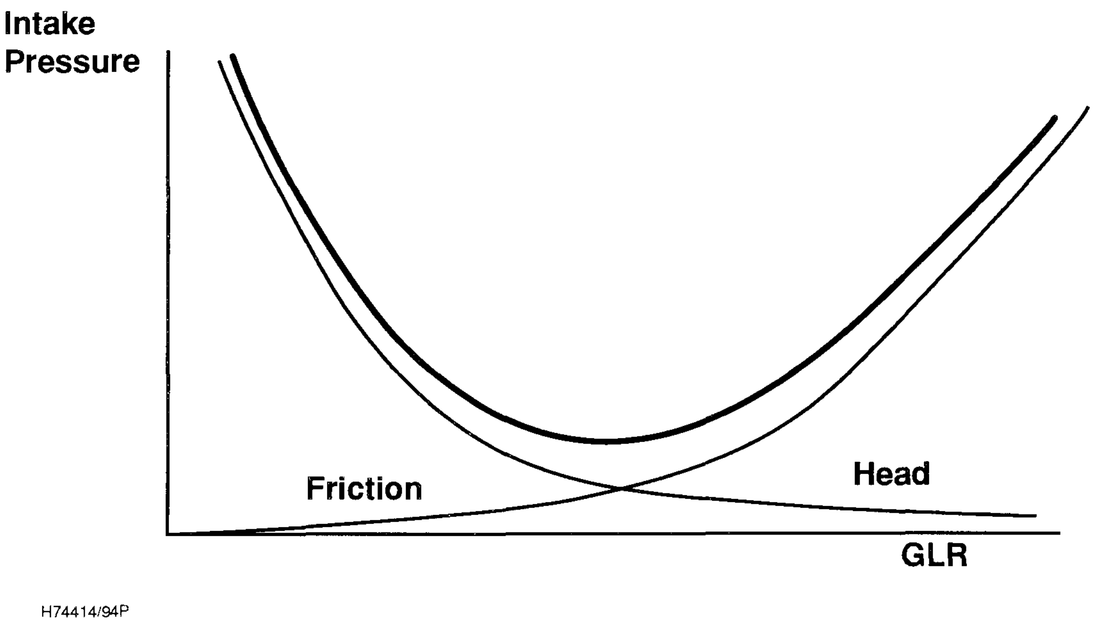


Figure A.10. - Effect of Head & Friction on Vertical Pressure Losses.

Now consider representing tubing performance with different parameters; intake pressure (P_{wf}) and flow rate (Q). In this case the GLR is fixed as in the case of a naturally flowing well and intake pressure is plotted against flow rate to determine the minimum intake pressure as a function of flow rate (Figure A.11.).

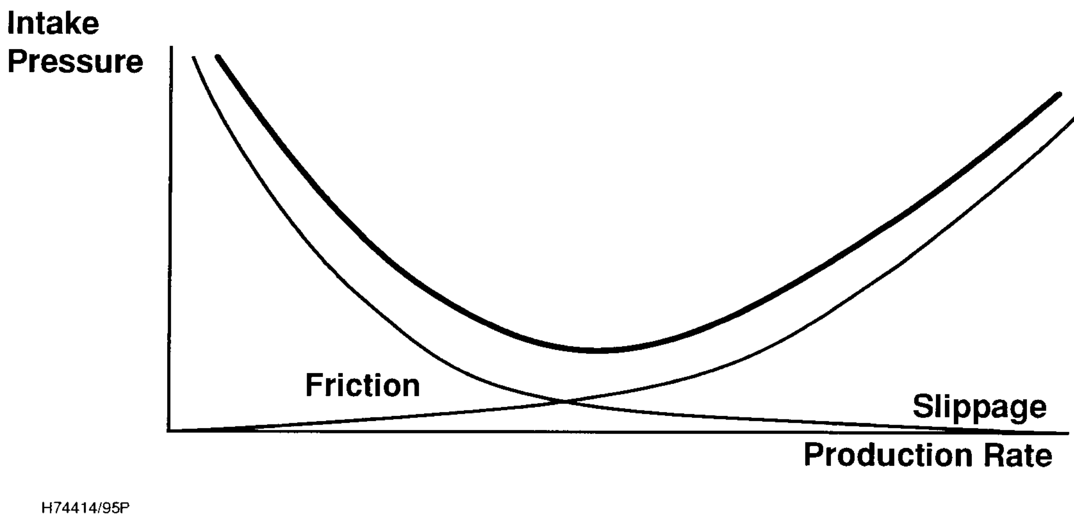


Figure A.11. - Effect of Slippage and Friction on Vertical Pressure Losses

Initially, since the flow rate is low, the resistance to flow is negligible and the tubing intake pressure is approximately equal to the hydrostatic head of the liquid column.

If a very small quantity of gas is now introduced, the overall density of the gas/liquid mixture should be reduced and so for the same liquid flow rate, the tubing intake pressure will be reduced. However, the introduction of a few gas bubbles will not reduce the tubing intake pressure significantly. This is because the high density difference between the liquid and the gas causes the gas to rise rapidly through the liquid to the top of the tubing, so that its effect in reducing the liquid density is minimal. This is the phenomenon called "slippage".

As the volume of the gas flowing in the liquid is increased, slippage still occurs but to a lesser extent. The effective mixture density is gradually reduced and so is the tubing intake pressure.

Increasing the gas injection rate with a constant liquid production rate increases the total mass flow rate which, in turn, increases the frictional effects. At some gas injection the energy loss due to friction will exceed the benefit gained by reducing the mixture density and the total energy loss in the system will rise.

Thus for a particular tubing producing from a given depth at a fixed production rate, there is an optimum GLR which corresponds to the minimum energy needed to lift the gas/liquid out of the well. At lower gas/liquid ratios slippage occurs, while at higher gas/liquid ratios frictional losses dominates.

The curve showing the relationship between tubing intake pressure and the flow rate is called the tubing Intake Pressure Curve (IPC). It is of most use because it can be compared with the inflow performance relationship to establish how much the well will produce at surface against the prevailing back pressure. A similar curve, called the Tubing Performance curve (TPC), shows the relationship between the tubing head pressure and the flow rate. This is useful because the tubing head pressure is a directly measurable quantity.

In Figure A.12. an intake pressure curve for a given tubing is shown on the same graph as the inflow performance relationship for a given reservoir. Each curve describes the relationship between the flow rate and bottom hole pressure, but for two different systems; flow from a reservoir, and flow through a tubing.

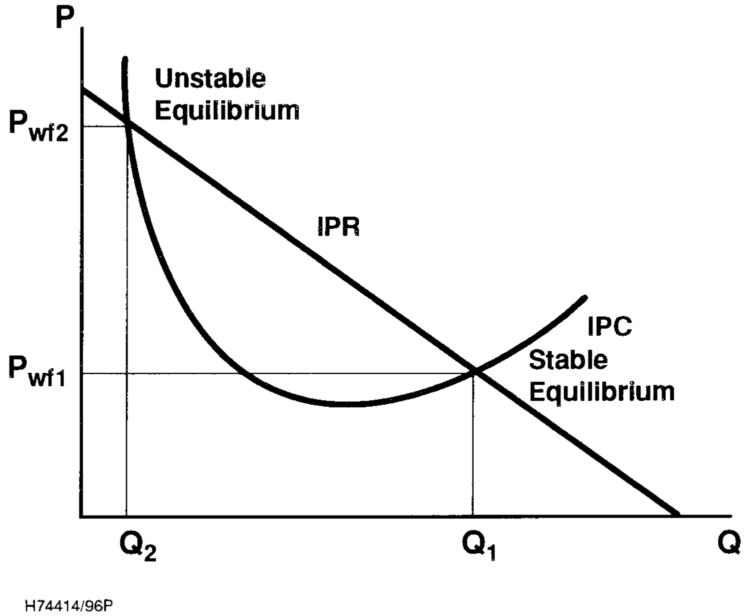


Figure A.12. - Intersection of IPR and IPC

For the reservoir and the tubing to be operating in equilibrium, the flowing and pressure conditions at the bottom of the well must be the same for each case. This occurs at the conditions defined by the intersection of the two curves (point 1), so this is the stabilised production rate that the system will maintain.

Note: that the IPR and IPC have a second intersection at a lower production rate. At the lower production rate, the well is producing under conditions of unstable equilibrium. If the flow rate reduces slightly from the point of intersection, the tubing requires more pressure than the reservoir can provide. The tubing acts as a choke in this situation and the well dies. At a slightly higher production rate, the tubing requires less pressure than the reservoir is supplying, so the reservoir is driving the tubing to a higher production rate. The production rate will therefore rise until the second intersection is reached, which is the point of stable equilibrium.

A.3. Choke Performance

It is normal practice to control the rate at which a well flows by installing a restriction in the wellhead. As well as technical considerations, the economic climate or local government restrictions may make it necessary to limit the off take rate to less than the well can manage. In summary, the production rate may have to be restricted in order to:

- Produce the reservoir at the most efficient rate to maximise the economic returns.
- Limit the well off take rate to that decreed by local government.
- Limit the drawdown and flow rate to prevent sand entry into the wellbore.
- Prevent the coning of water or cusping of gas which may be caused by producing the well at too high a rate.
- Protect surface equipment from fluctuations in the production rate.
- Eliminate the effect of downstream pressure variations on the producing well.

The conditions governing multiphase flow through a small restriction are complex and, as in the case of vertical flow, the equations that are used to describe this phenomenon are empirical, derived from observing wellhead pressures and flow rates in the field.

One of the requirements of a choke is that it isolates the producing well from pressure fluctuations which occur downstream of the wellhead so that random separator and flow line pressures do not control the well. This condition exists if the rate of flow through the choke is greater than or equal to the speed of sound in the flowing medium. This condition is called "critical flow". For single phase gas flowing through a choke, critical flow exists if the following condition applies:

$$P_{th} > 1.9P_{fl}$$

where:

P_{fl} = flow line pressure

For multiphase flow (oil, gas and water), critical flow exists if:

$$P_{th} > 1.7P_{fl}$$

For critical flow conditions, an empirical equation for the tubing head pressure has been derived as follows:

$$P_{th} = \frac{AR^{B}Q}{S^{C}}$$

where:

P_{th} = tubing head pressure

R = GLR

Q = gross liquid flow rate

S = Bean diameter

The constants A, B and C, are dependent on the fluid properties and the type of choke in use, and vary from field to field. Derivation of these constants is therefore empirical.

The graphical representation of this equation is called the Choke Performance Curve (CPC).

A.4. A Complete Model of a Flowing Well

A complete model of a flowing well is shown in Figure A.13. It shows the IPR, IPC, TPC and CPC construction and how these relate to the various pressure drops in the production system.

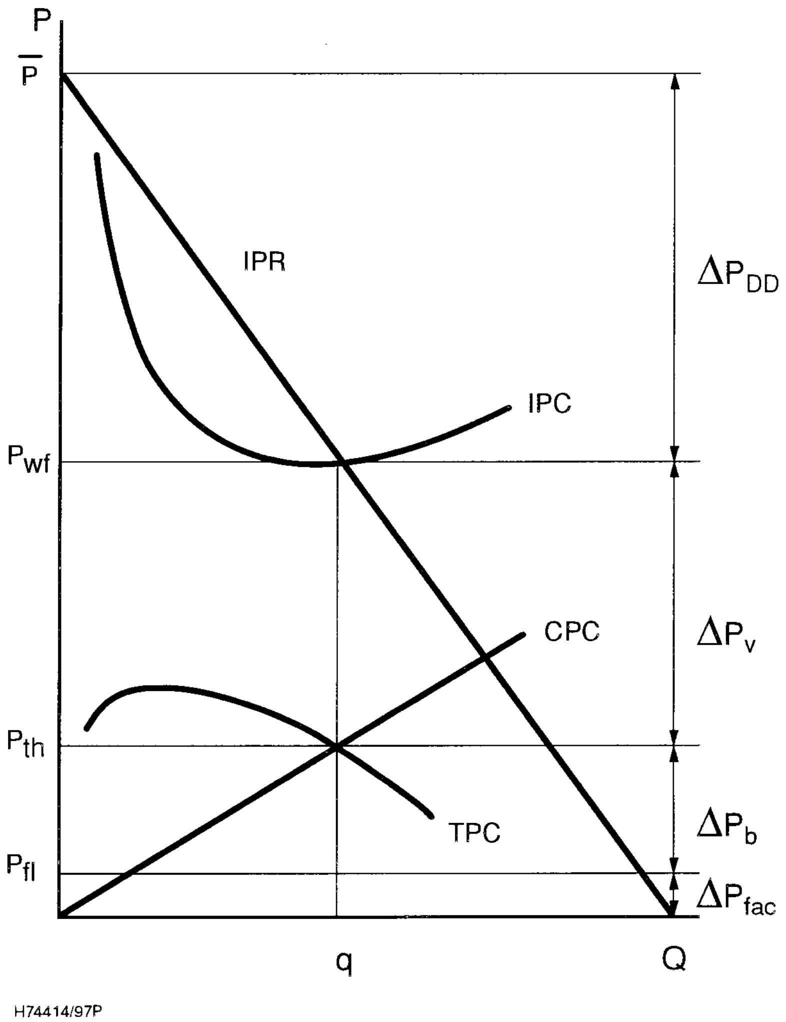


Fig. A.13. - Final Representation of Flowing Well.

B APPENDIX B: DETERMINATION OF THE EQUILIBRIUM CURVE.

The construction of an equilibrium curve is best illustrated using a pressure vs. production rate diagram as starting point, since during the construction process the required data to build the more practical depth vs. pressure diagram is also generated. To do this follow the steps below.

B.1. Step One:

Is to define the relationship between P and Q at the bottom of the well. This is reflected by the IPR. For convenience the axis are rotated as shown in Figure B.1. The intersection of this curve with the two axes also defines the range of Q and of P.

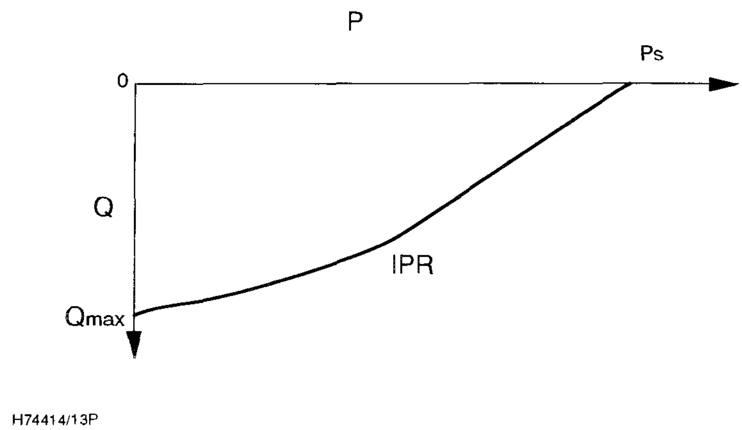


Figure B.1 - IPR curve

B.2. Step Two:

The surface conditions are defined. Depending on the dimensions of the flowline and of the operating pressure of the surface facilities, the well head pressure required for surface transport of the production can vary. The well head pressure curve (at zero depth) is added to the plot. See Figure B.2.

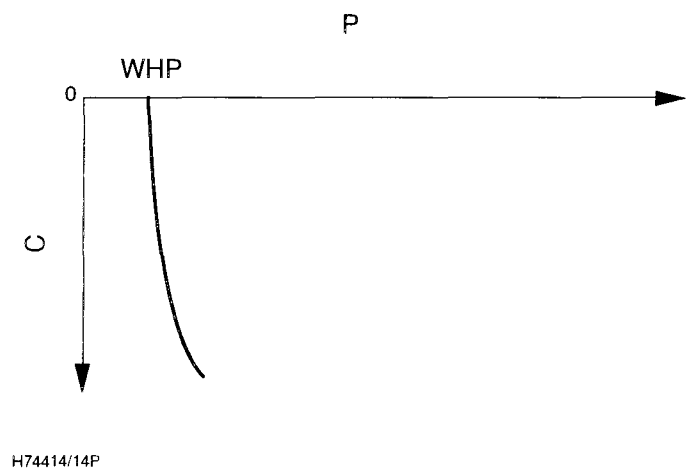


Figure B.2 - Well head pressure curve

Note: It is worth while pointing out that contrary to the usual practice of installing a bean at the well head or at the manifold when the well is on natural flow, no bean should be installed in a well on gas lift since it would dissipate part of the energy supplied to lift the well. In other words the minimum FTHP should be achieved for efficient lift.

B.3. Step Three:

For the bottom section of the conduit, calculating from bottom up, for a set of flow rates in the range 0 to Q_{max}, starting with the P_f defined by the IPR for that rate, and using the appropriate gradients for *natural* GLR , locate and plot the pressure at selected depth intervals from bottom to surface. Curves through the different points representing pressures at the same depth yield *tubing performance curves* for natural flow for conduit lengths from bottom to the specified depth. See Figure B.3.

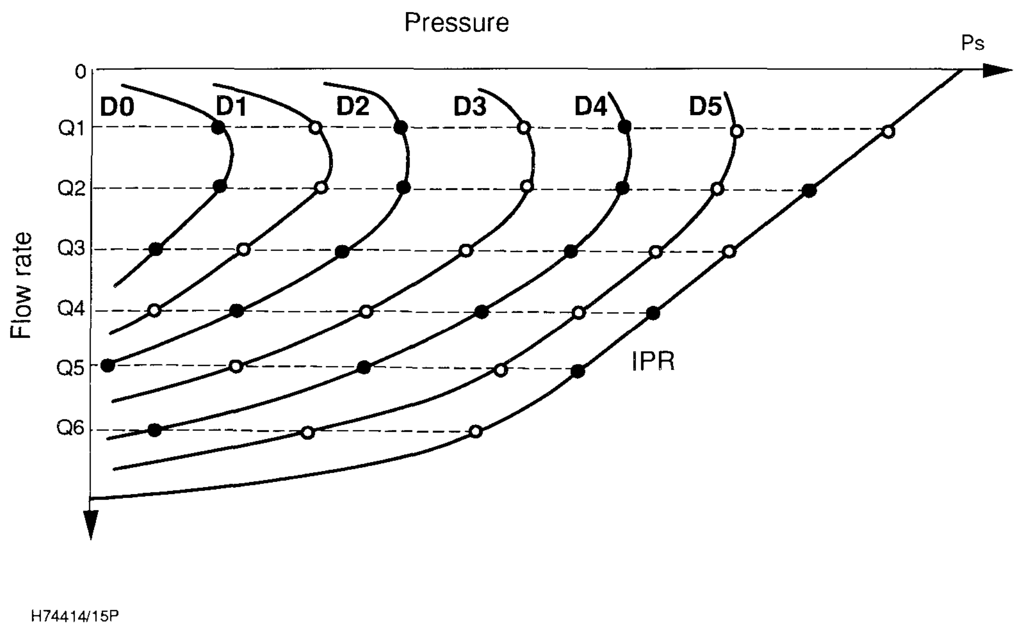


Figure B.3 - Tubing performance curves for natural flow

B.4. Step Four:

For the upper section of the conduit, calculating from the top down, starting with the well head pressure as defined by the curve in Figure B.2 and with the appropriate gradient curves for **either** optimum or attainable IGLR, locate and plot the pressure at the same depth levels and set of Q's as in step three.

Curves through the different points representing pressures at the same depth yield *intake pressure curves* for gas lift GLR for conduit lengths from top to the specified depth. See Figure B.4.

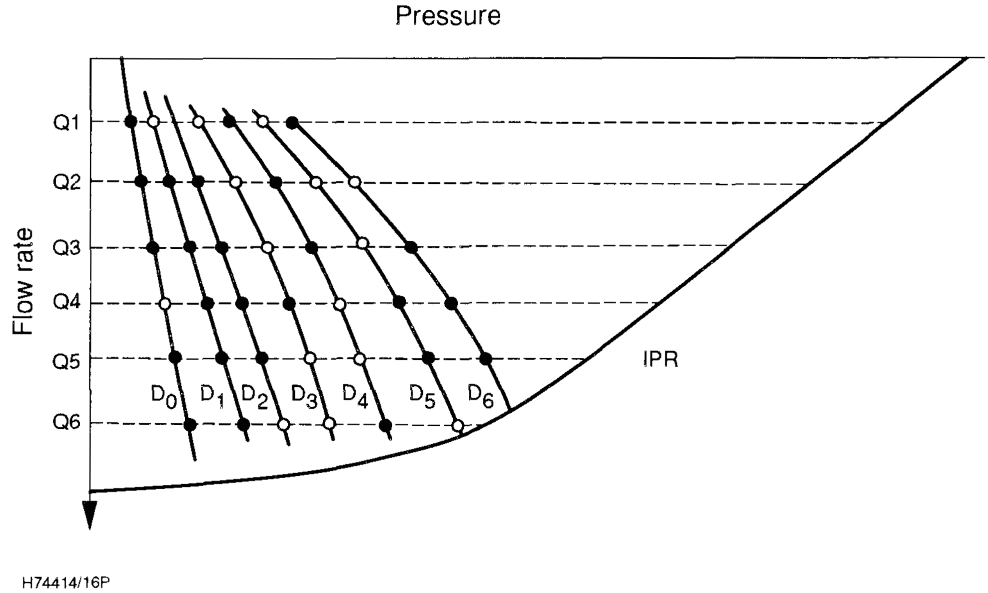


Figure B.4 - Intake pressure curves at various depths

B.5. Step Five:

Both sets of curves in Figures B.3. and B.4. are superimposed. For each depth level, the intersection of the corresponding intake pressure curve and the conduit performance curve locates the equilibrium pressure in the production conduit for the assumed volume of gas injection at that depth. A curve through the equilibrium pressure for all levels considered is known as the *equilibrium curve*. See Figure B.5.

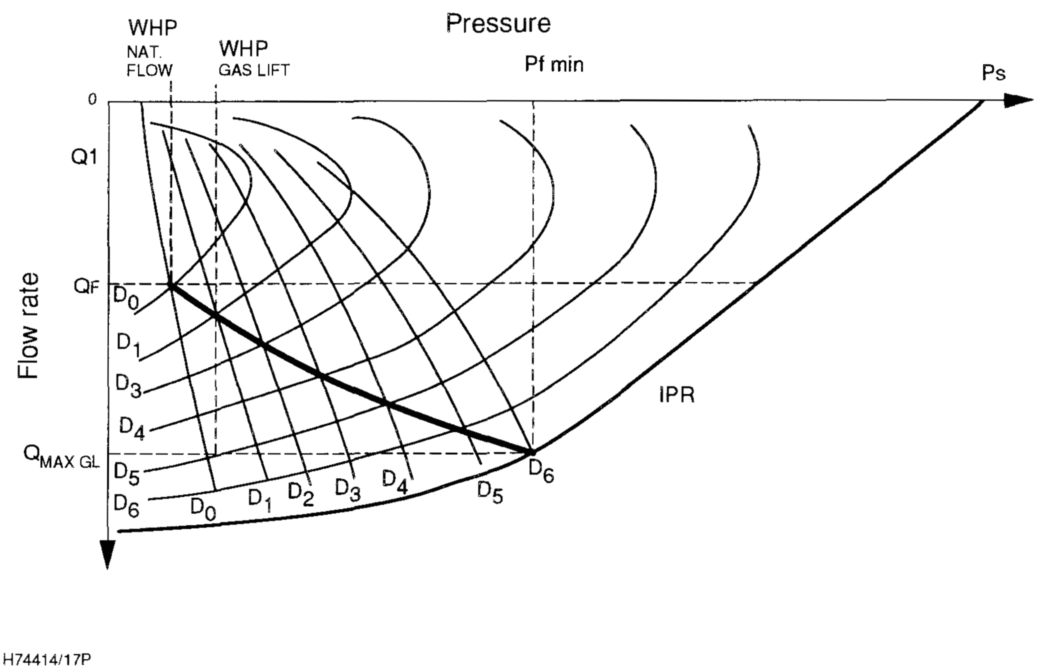


Figure B.5 - Equilibrium curve P vs. Q.

The intersection of the equilibrium curve with the IPR defines the minimum intake pressure possible with the available gas lift. The corresponding production rate is therefore the maximum attainable and corresponds to injection at the bottom of the well.

The intersection (if there is one) with the curves at level Do define the well head pressure of the well on natural flow (or with gas injection at the surface which has no effect). The corresponding Q is of course the natural flow rate of the well.

Injection at intermediate levels result in intermediate flow rates as defined by the equilibrium curve. However, the depth is not easy to read in this plot. This can be solved by transfering the intersections defining the equilibrium curve to a pressure vs. depth diagram having a common pressure axis with the P vs. Q plot as shown in Figure B.6.

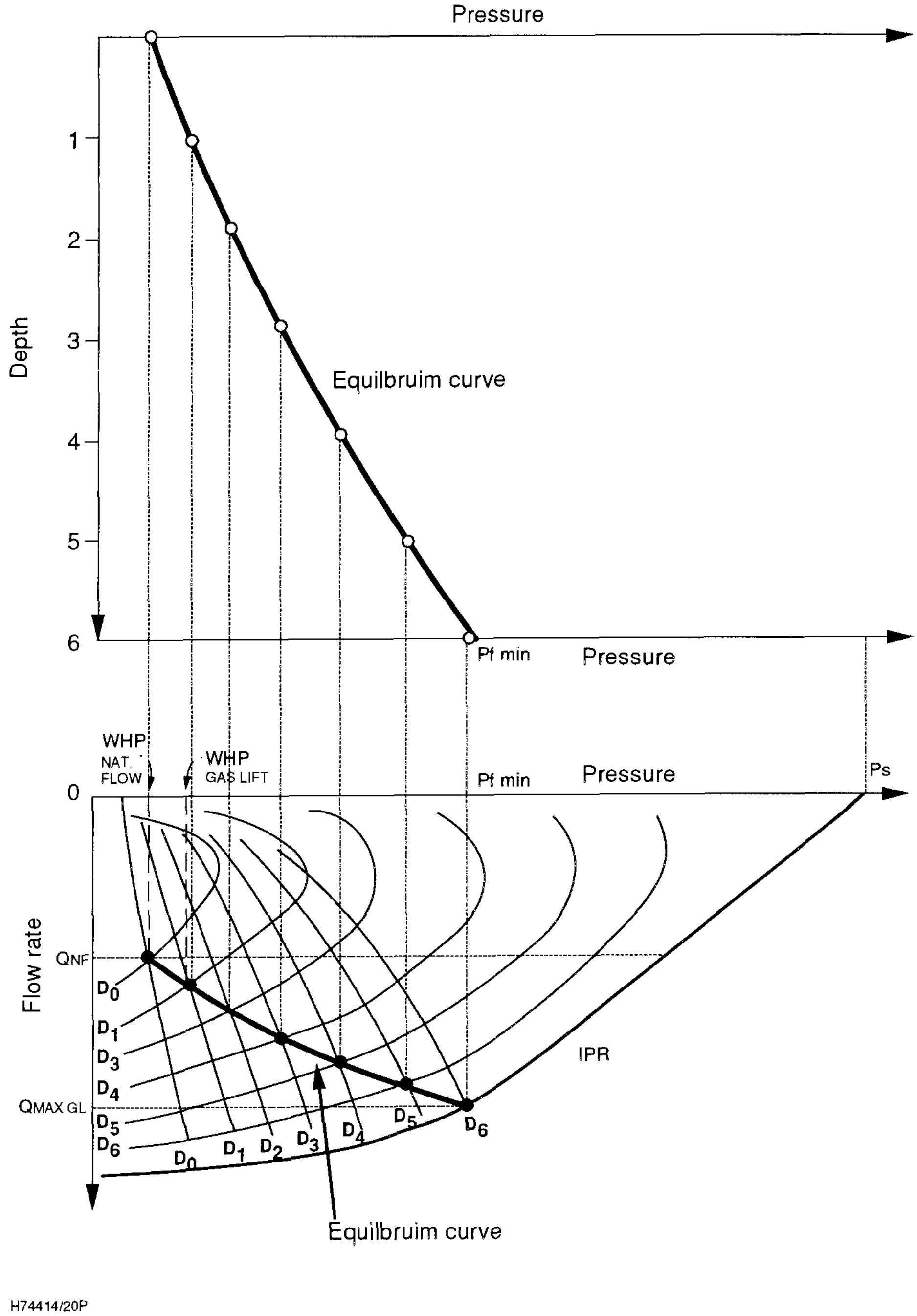


Figure B.6. - Equilibrium curve - P vs. D construction

The diagrams in Figure B.6. contain most of the data required for the gas lift design of the well represented.

B.6. Example:

Given a surface gas injection pressure determine the maximum injection depth, the production rate when the well is on gas lift from that depth, and the flowing gradients in the production string above and below the point of injection.

Using Figure B.6., the surface gas injection pressure is located in the P vs. d diagram. As from that point, the gas injection gradient is plotted . Its intersection with the equilibrium curve defines the maximum depth at which gas can be injected with the given surface pressure. In practice, a pressure drop across a valve or an orifice is required and therefore the attainable maximum depth is correspondingly higher than the theoretical maximum. See Figure B.7.

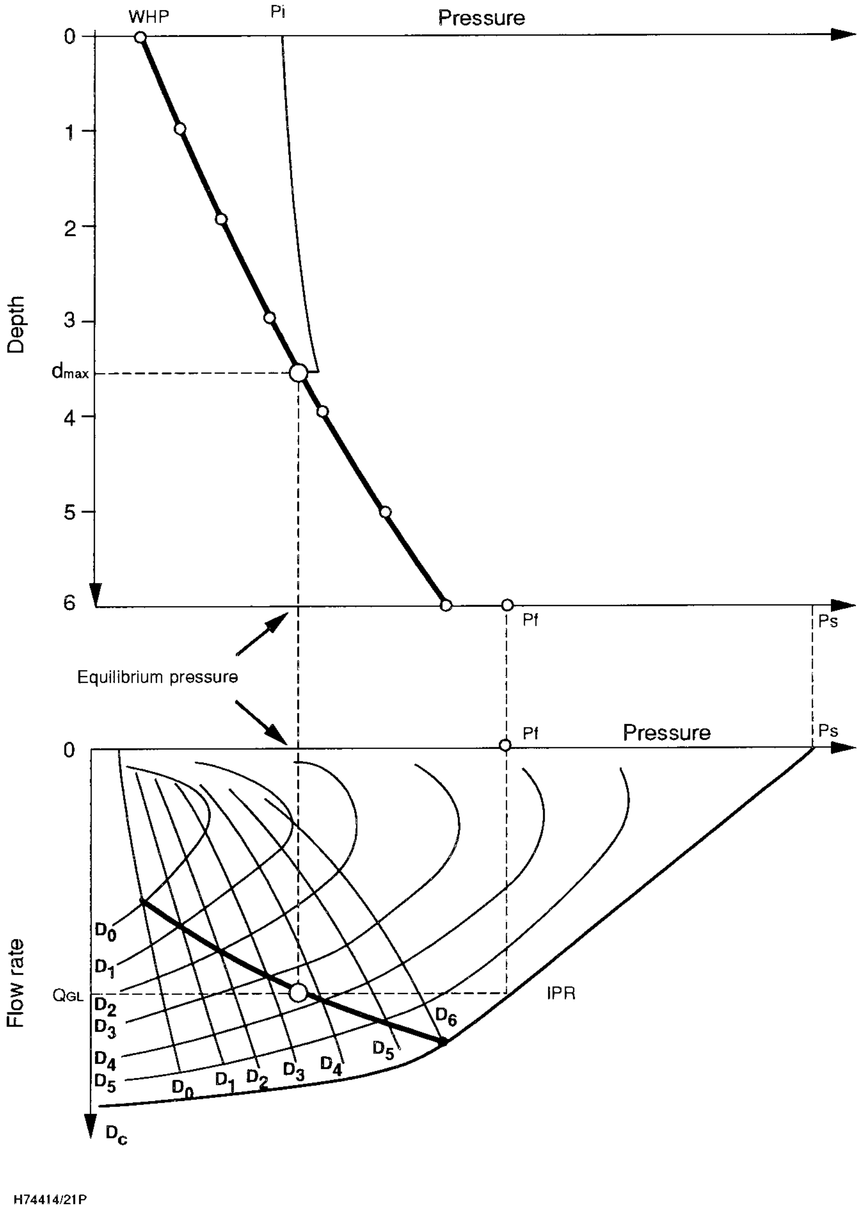


Figure B.7 - Establishing maximum gas injection depth

Going to the P vs.Q diagram, the equilibrium pressure found above defines the production rate for the well on gas lift from that depth. From the curves in the P vs. Q diagram the flowing pressure gradients above and below the point of gas injection can be found by locating the intersections of a horizontal line through Q_{GL} with:

a. above the point of injection: the intake pressure curves for gas lift GLR, and

b. below the point of injection: with the conduit performance curves for natural GLR.

The pressures located above are transferred to the P vs. D diagram at the corresponding depths, and the flowing gradient curves are drawn through these points. See Figure B.8:

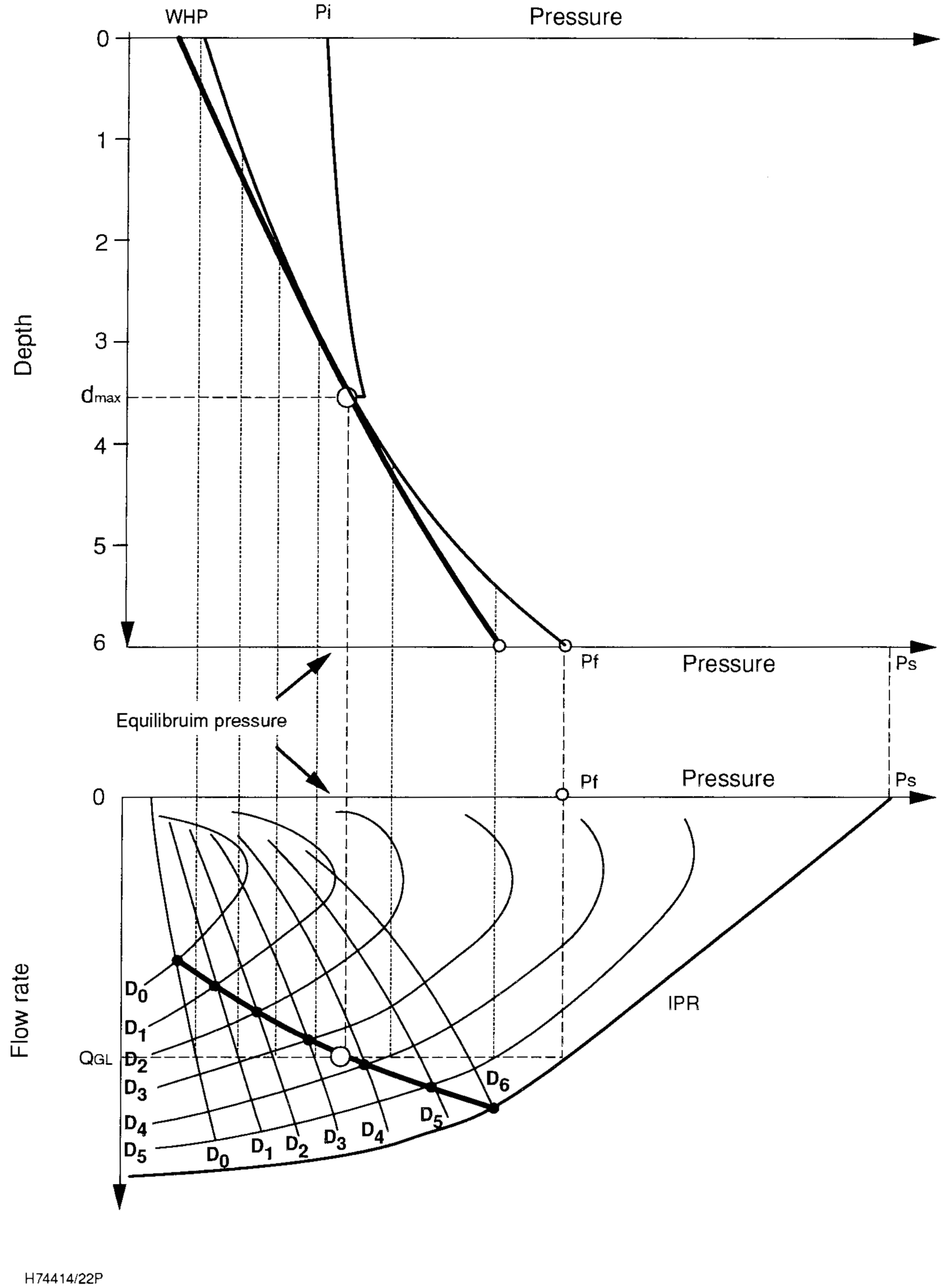


Figure B.8 - Construction of flow gradients above and below the gas injection point

The complete set of diagrams is shown again in Figure B.9. It is stressed that the purpose of this diagramatic approach is to show and establish as clearly as possible the interrelationship between surface injection pressure, injection depth, production flow rate and gas lift GLR allowing the

engineer to define the range of possibilities for gas lift and work out the design in detail for a specific set of conditions.

It should be remembered that the diagrams are only valid for the set of conditions on which they were based. Clearly, if the IGLR, tubing size, BS&W, PI, WHP etc. change, the shape of the diagrams will also change.

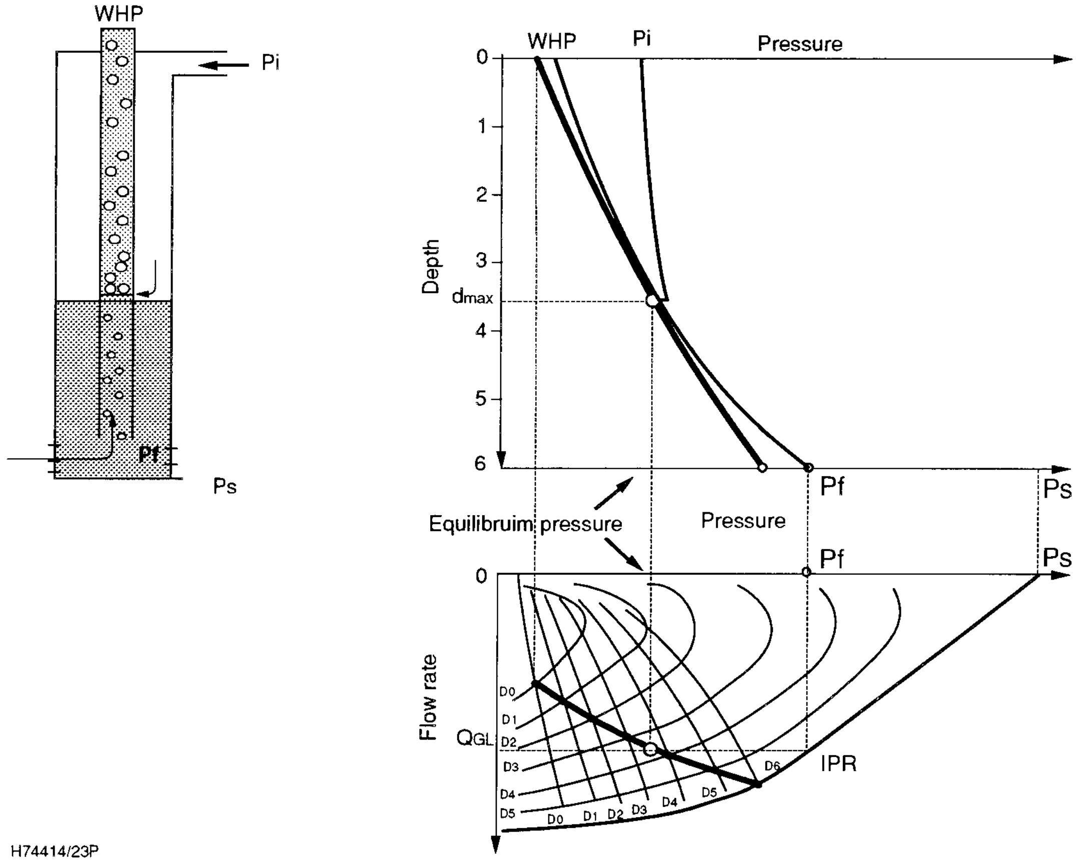


Figure B.9 - Equilibrium curve inter-relationships.

C APPENDIX C.

C.1: DESIGN EXAMPLES FOR PRODUCTION PRESSURE OPERATED VALVES.

The following data will be used:

(Data taken from worked out example in EP report 37419)

Well depth			8250 ft.
7" casing (N 80,23lbs/ft) at			7999 ft
2.875" EU tubing at			8000 ft
Tubing area	m	=	4.680 sq.inch
Annulus area	n	=	25.266 sq.inch
Static bottom hole pressure at 8000 ft.	Ps	=	1900 psig.
Productivity index	PI	=	0.50 b/d/psi.
Formation gas oil ratio	Nat. GOR	=	400 cf/b
Flowing tubing head pressure	THP	=	50 psig
Static kill fluid gradient	Gs	=	0.432 psi/ft
Geothermal gradient	Gts	=	0.014 °F/ft
No water influx			

For lift gas available:

Maximum surface gas injection pressure	P_{imax}	=	600 psig
Operating surface gas injection pressure	$P_{iop.}$	=	550 psig
Average gas gradient (gas gravity 0.78)	Gg	=	0.022 psi/ft
Residual gradient	Gr	=	0.060 psi/ft
Injection gas available			100,000cuft/d
Bottom hole temperature at 8000 ft.	Tb	=	212 °F
Oil gravity	33°API	(S.G. =0.8602)	

Tubing gradient curves from Report EP-35500

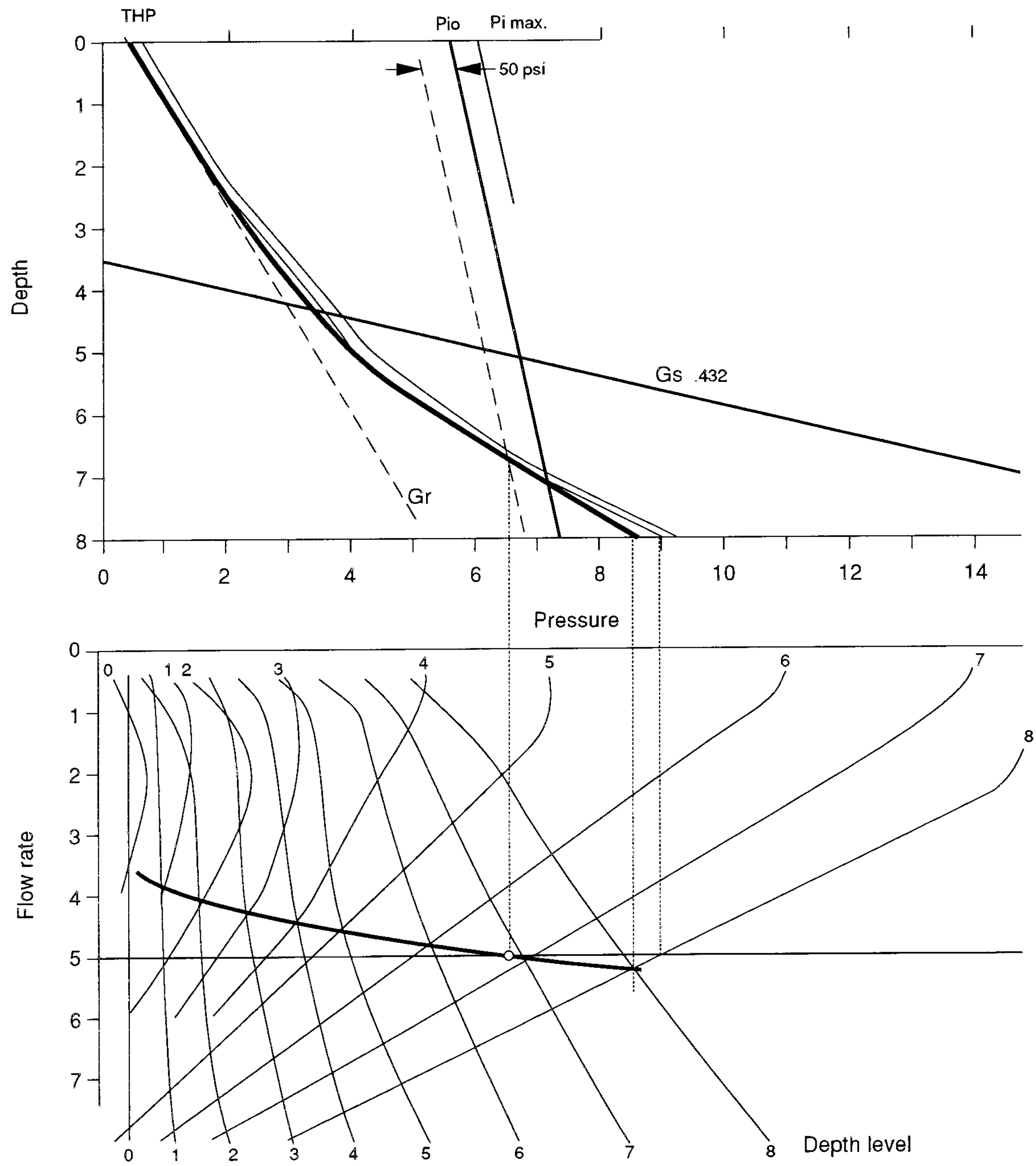
Gas lift valves: continuous flow-production pressure operated, pressure loaded bellows valves.

Minimum pressure differential across valves: 50 psi

Using the given data a plot defining the boundary conditions is prepared (Figure C.1). It contains the gas injection pressure gradient curve, the line representing the static gradient in the well, the residual gradient curve, the tubing performance and intake performance curves required to define the equilibrium curve, the ultimate flowing gradient curve when the well is producing with gas injection at the maximum depth to still maintain the specified 50 psig differential across the bottom valve. The

maximum depth is located at the intersection of the equilibrium curve and a curve parallel to the gas injection pressure curve 50 psi to the left (dotted line)

To ensure that the valves do not re-open when the well is producing at the ultimate rate a valve closing pressure curve (or transfer pressure curve) is selected 30 psi to the right and parallel to the ultimate flowing gradient curve. The magnitude of this design margin is selected by the designer and should be as small as possible but enough to cover fluctuations in the ultimate pressure gradient. (See chapter on design factors.)



H74414/45P

Figure C.1. - Boundary Conditions.

C.1.1 Case 1:

Design a gas lift string assuming that the well is full of 0.432 brine when gas injection is initiated.

The worked out design is shown in figure C.2.

In this case the depth of the first valve is located at the intersection of an static gradient line starting at the THP with the operating injection pressure line. Since Pi_{max} is initially available and this pressure in this example is 50 psi higher than the operating injection pressure the requirement for a 50 psi minimum differential across the valve is satisfied.

Valves 2 to 6 are spaced using static 0.432 gradient lines between the selected transfer pressure curve and the dotted line 50 psi to the left of the injection pressure curve.

> *Note:* that the transfer pressure for valve 5 is very near to the pressure on a static gradient line plotted as from the Ps.=1900 psi of the well. In other words, the initially high bottom hole pressure imposed on the formation by the initial column of kill fluid has been decreased by unloading the well via 5 valves to almost reservoir pressure. Further unloading will generate a draw-down and and the well will to start to flow.

Gas injection through valve 6 causes the pressure in the tubing to decrease towards equilibrium pressure at that depth. However,the selected transfer pressure will be reached before the equilibrium pressure is achieved.

To find the flow rate at the moment when the valve is about to close, the depth of injection is located on the equilibrium curve of the Q vs.P diagram from that point a tubing performance curve is interpolated up to the transfer pressure. A horizontal line through that point (Q_1= 422 b/d) is used to locate the flowing pressures on the tubing performance cerves below the point of gas injection which are required to define the flowing gradient curve for Q = 422 b/d at natural GOR.

Valve No. 7 is located at 6150' by the intersection of the flowing pressure gradient below V6 with the dotted line to maintain the 50 psi dP.

Using the same procedure as for valve No.6 the flow rate when the transfer pressure of valve 7 is reached is found to be Q_2=467 b/d. The flowing gradient for that rate is plotted and the depth for valve No.8 is located at 6450 ft. Corresponding rate is Q_3= 475 b/d.

Repeating the procedure yields the depth for valve No.9 at 6530 ft. This is only 80 ft deeper than valve 8 It can be seen that the spacing for the following valve would be too small.

The flow rate obtained when lifting from valve 9 is found to be Q_4 = 493 B/d , very near the theoretical maximum of 500 b/d that would be obtained by lifting from the intersection of the dotted line representing injection pressure minus 50 psi minimum dP. Therefore V9 is taken to be the final injection depth.

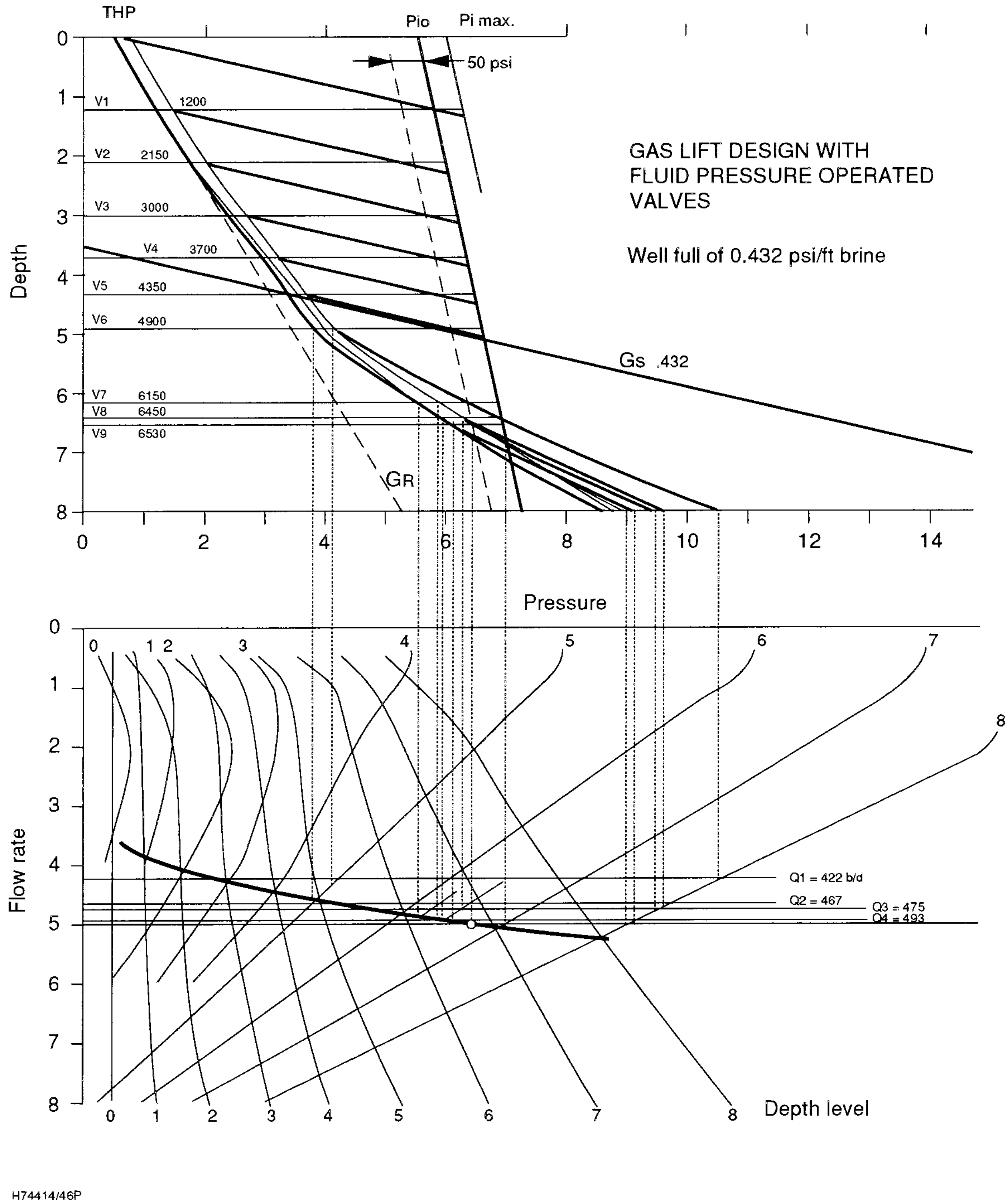


Figure C.2.

To illustrate the effect that changes in the assumptions have on the design, the following cases have been worked out and are given in the following examples.

C.1.2 Case 2:

Design a gas lift string with the same data as before but use the static gradient to space all valves evaluate the effect of this approach on string design.

From figure C.3. it can be seen that to reach up to valve No.6 the design is obviously identical to the one in figure C.2. Thereafter, using the static gradient instead of the flowing gradient for the following valves, it would require another 7 valves (rather than the 3 in the first design) to reach an injection depth of 6400 ft. to achieve a comparable production rate of 490 b/d. However, the spacing of the last few valves would be too small for practical purposes and would probably be omitted accepting the consequent reduction in flow rate.

It is clear that, given reasonably good well data, an unnecessarily high design margin has been used in this design.

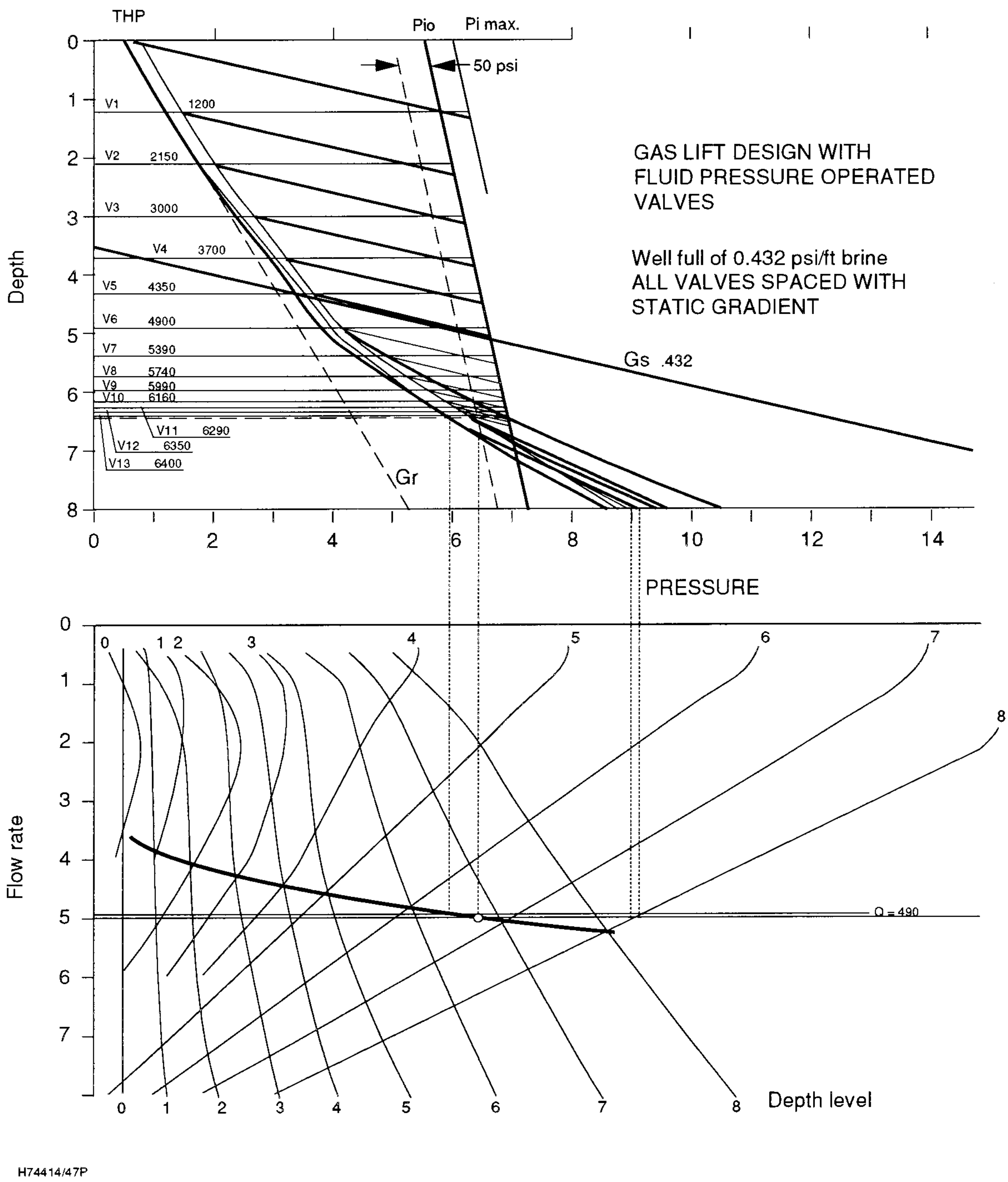


Figure C.3 - Case 2

C.1.3 Case 3:

Show graphically how unloading will take place when valve 7 is placed higher than the maximum depth.

Comparing the spacing for valve No.7 in figures C.2 and C.3 it can be seen that this valve placed in the range 5400 to 6150. See figure C.4.

The 6150 ft. depth was determined by using the calculated actual gradient existing below valve No. 6 when the gas injection is taking place at V6 level long enough for the pressure in the tubing to reach transfer pressure. At that moment the well was flowing at 430 b/d. and the fluid level in the injection conduit has been depressed to the equivalent of 50 psi deeper than the 6150 level.

If valve no. 7 had been placed at 5400, the fluid level in the injection conduit would reach that depth when the well is flowing at 272 b/d. When the flow rate reaches 320 b/d the pressure differential across valve 7 is already 50 psi and gas is therefore being injected at that level. Note that at that moment the pressure just upstream of the valve 6 would be at point 'b' corresponding to *gas lift GOR* gradient for 320 b/d. Point 'a' just below the valve is on the *natural GOR* gradient curve for 320 b/d. The pressure differential a-b drives the flow rate to increase towards the equilibrium flow rate.

The transfer pressure for valve 6 has not yet been reached at that time and therefore injection through both valves (and in the design of figure C.3 also through valve 8) will continue until the pressure decreases enough to close valve 6 which happens when the flow rate reaches 430 b/d.

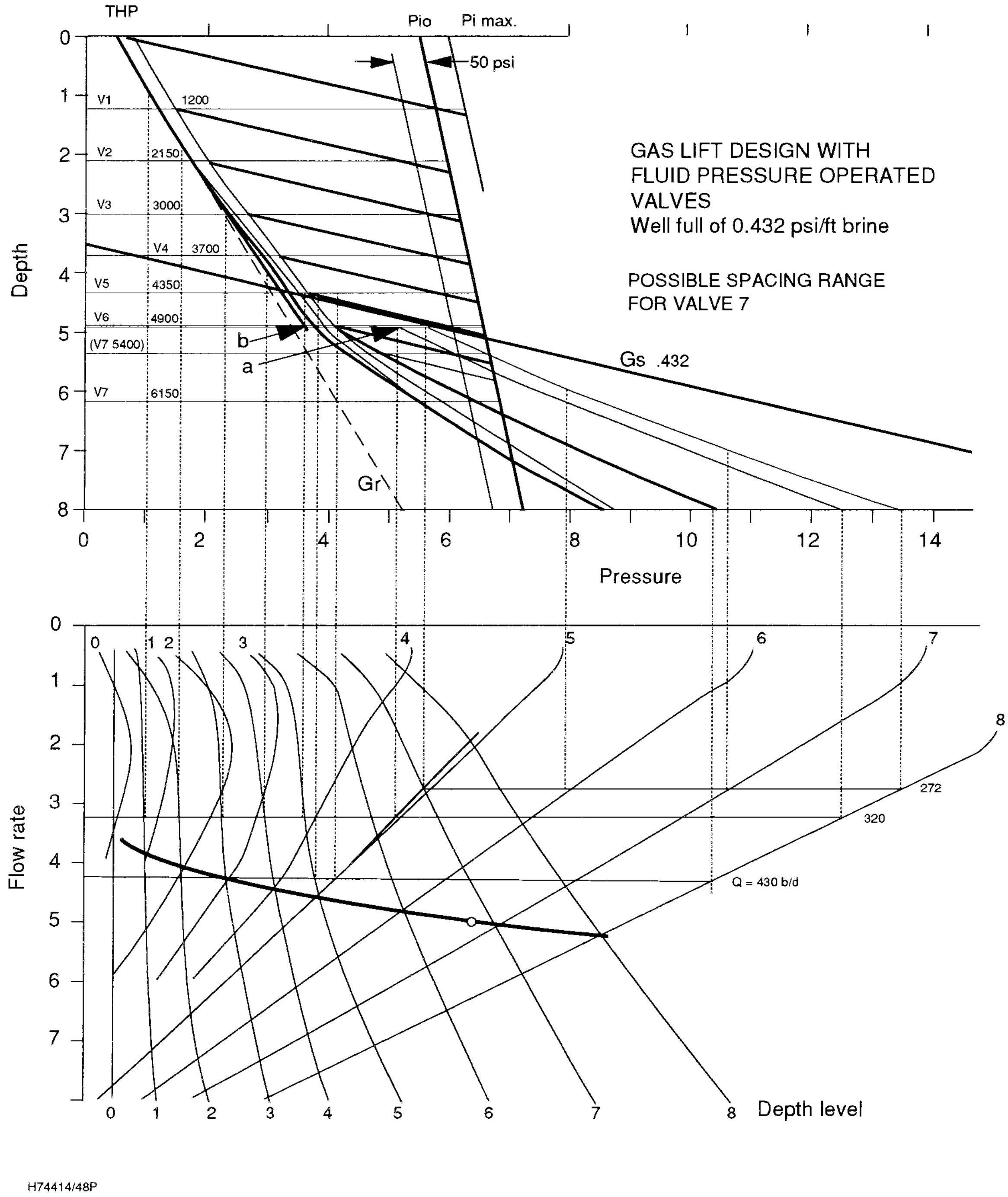


Figure C.4. - Case 3

C.1.4 Case 4:

To illustrate the effect that the initial depth of the liquid fluid level has on valve spacing, design a gas lift string assuming that the well is left without gas injection until the fluid level reaches its equilibrium level i.e. the depth at which a dead fluid column (water or oil) would balance the static reservoir pressure. See figure C.5 below.

The gradient for 33° API oil is .3725 psi/ft.

If the reservoir pressure (1900 psi) is balanced by an oil column, for THP= 0 the fluid level would be at 8000 - 1900/ .3725 = 2900 ft.

If the column is water, the fluid level would be at 3602 Ft.

The first valve can be placed at the depth to which the fluid level in the annulus will be depressed when the gas injection pressure (Pi max. minus 50 psi) is applied. This depth is easily determined graphically if the position of the fluid level is known for two different injection pressures.

The fluid level for zero injection pressure has already been calculated. A second point can be calculated as follows:

If enough pressure was available to U tube fluid until the level in the tubing reached the surface, the level in the annulus would be depressed to :

Fluid level - Fluid level x (Tubing area/annulus area)

If the column is water :

$$L_{water} = 3602+3602 \times 4.680/ 25.266 = 4269 \text{ Ft}$$

If the column is oil:

$$L_{oil} = 2900 + 2900 \times 4.680/ 25.266 = 3437 \text{ Ft}$$

To determine the position of the fluid level when surface gas pressure is ($Pi_{max.}$-50), the two known positions of the fluid level are plotted and joined by a straight line. The intersection of this line with the ($Pi_{max.}$ -50) traverse determines the required depth for valve No.1 to allow the specified 50 psi differential across the valve.

In figure C.5:

If well contains water., point 3602 ft at 0 pressure (L_{water}) is connected with point 'g' at intersection of line 'a' (water gradient as from 0 THP) with depth 4269 ($L_{water\ 2}$). The two points are connected with line 'b' and the depth for valve 1 found at intersection of (Pi_{max}-50) traverse is 3820 ft.

If well contains oil, following the same procedure intersection f at 3439 ft (L_{oil2}) is connected by line 'd' to 2900 ft at 0 psi (L_{oil}). The intersection with the (Pi_{max} - 50) traverse locates the depth for valve 1 for this case at 3190 ft.

In conclusion, it can be seen that in this example the depth at which valve 1 should be positioned is either:

3190 ft if the fluid column is oil

or

3880ft if the fluid column is water.

For the gas lift string design the shallow position is selected since it is possible (and rather likely) that the well will be closed-in at some point leaving an oil column in the tubing. Under this condition gas lift could not be initiated if the first valve is at 3820 ft. Note that this result is not immediately obvious since the general tendency is to assume that designing for a water column always yields a 'safe' design.

Valves No. 2,3 and 4 (well not flowing) are spaced using the.432 brine gradient to cover the case when the well has been left full of brine.

Valves No. 5 and 6 are spaced using the flowing gradients determined as previously indicated.

It is noted that in this case 6 valves are sufficient to achieve 492 b/d, near enough the theoretical maximum of 500 b/d

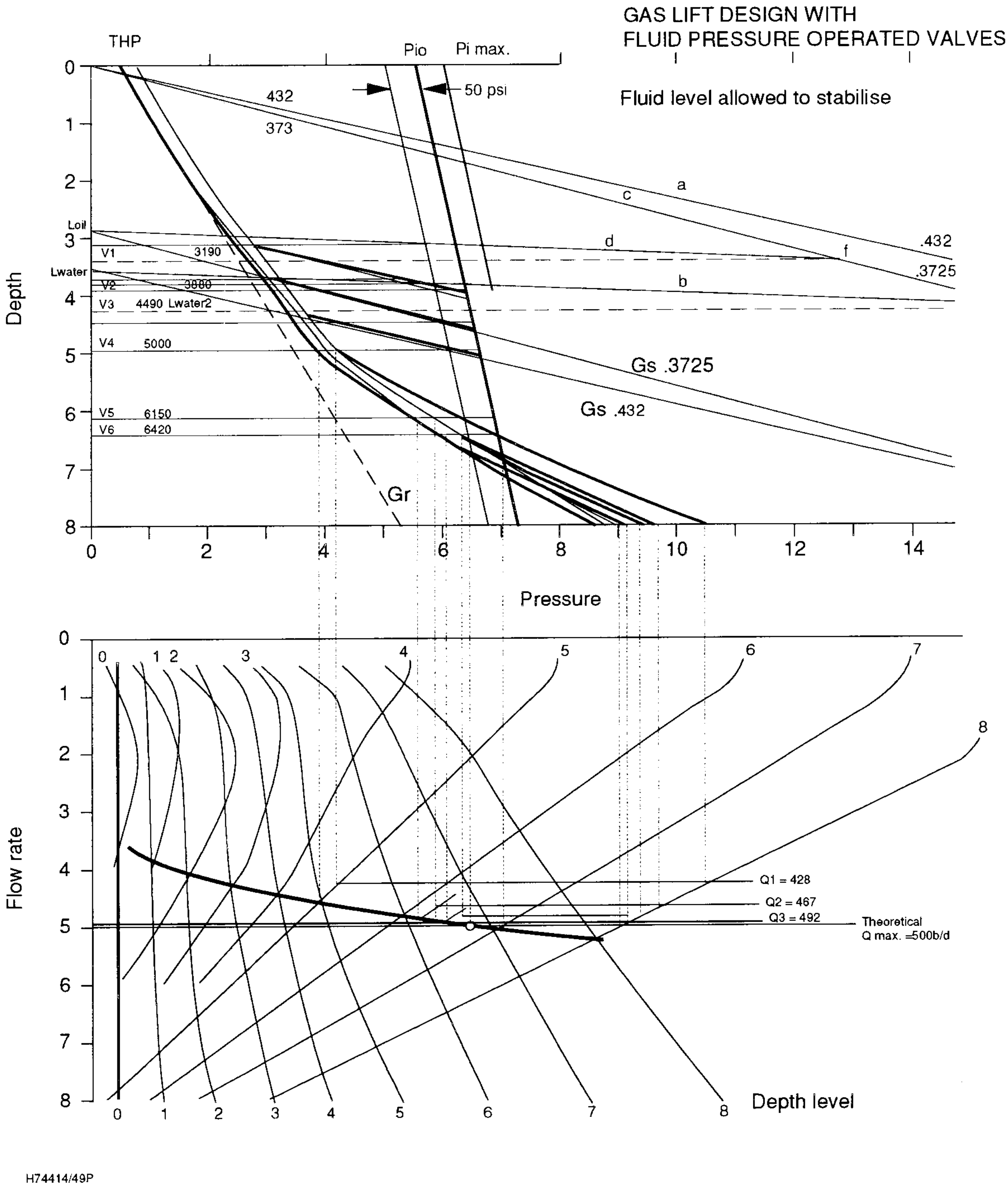


Figure C.5. - Case 4

C.1.5 Case 5:

In many cases gas lift is applied to a flowing well to increase the production rate. To illustrate the effect on valve spacing design a gas lift string for the same example well as in the previous cases but assume that the well is producing 355 b/d on natural flow before gas injection is initiated. (See figure C.6 below)

The intersection of the flowing performance curve for natural GLR at the 0 ft. level with the specified THP of 50 psi locates the Q on natural flow (355 b/d). The corresponding flowing gradient curve is defined by the intersections of an horizontal line through Q=355 and the tubing performance curves for natural GLR at the various depth levels. These pressures are transfer to the corresponding depths in the P vs.d diagram thus defining the flowing pressure traverse for 355 b/d.The first valve is located at the intersection of the Pi -50 gas injection traverse with the flowing gradient for 355 b/d.

Note that in this case it has been decided to use Pio and not Pimax. to space the first valve. This of course is the prerogative of the designer who in this case considered that a 50 psi design margin would give the design flexibility to work even if the natural flow gradient would increase. In this case using Pimax to space the first valve does not change the number of valves required nor significantly affect the attainable flow rate on gas lift. As in previous examples, the transfer pressure curve is plotted parallel to the ultimate flowing gradient curve and the second valve depth located by defining the flowing gradient at the time the transfer pressure for valve No.1 is reached.

The procedure is repeated to locate the depth for valve No.3.

Injecting at V3 level the equilibrium rate is 494 b/d, very near the theoretical maximum.

It is pointed out that to design a gas lift string as above one must be confident that the well will be able to sustain natural flow long enough to economically justify the design.

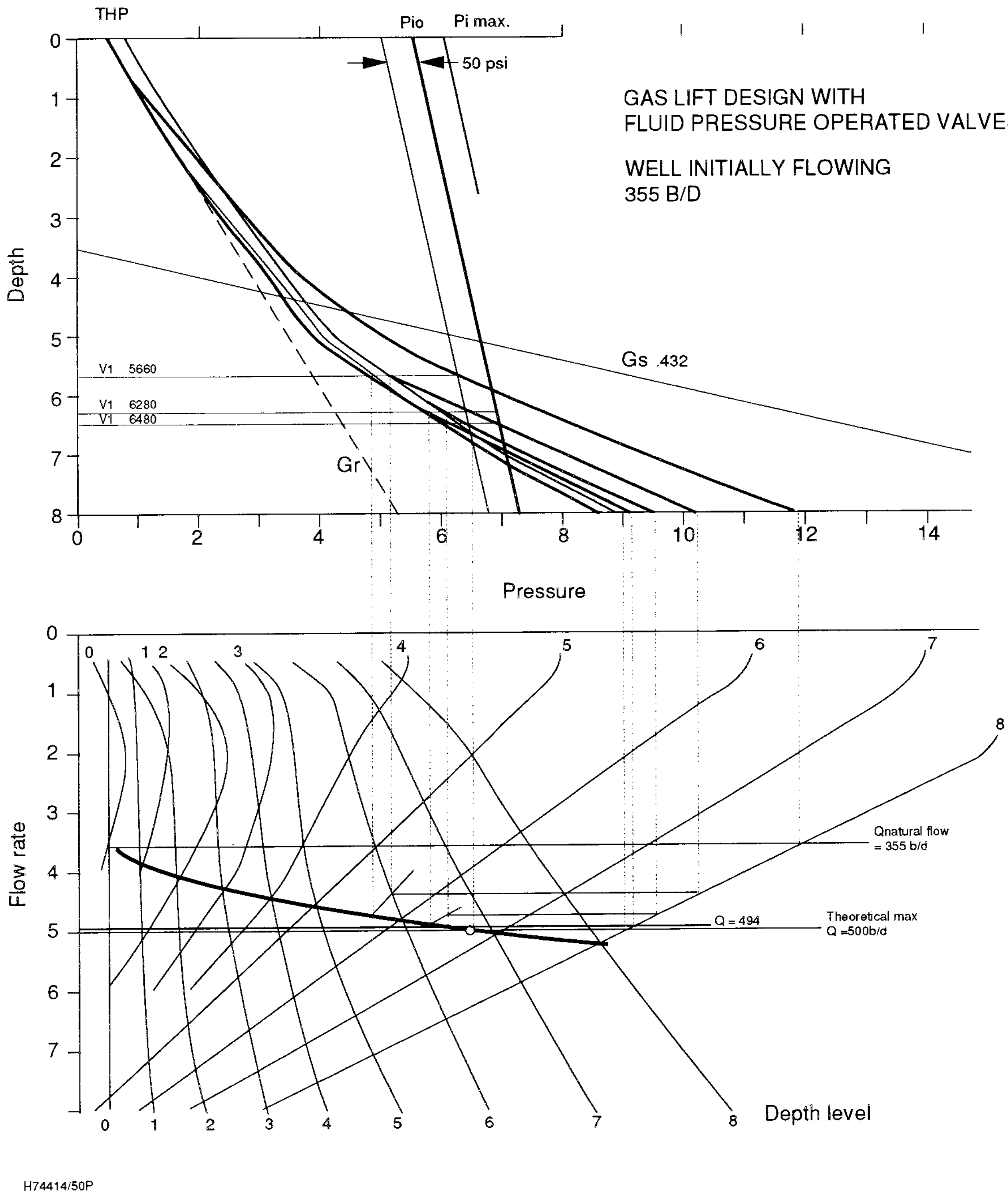


Figure C.6. - Case 5

C.1.6 Case 6:

Design a gas lift string as for case 1 but assume that only 20 psi pressure differential is initially required across the valves to see the effect of this assumption on the valve spacing and on the achievable gas lift flow rate.

Refer to figure C.7 below, where the worked out case is depicted.

> *Note:* that the theoretical maximum flow rate increases to 510 b/d reflecting the additional 30 psi injection pressure now available. The somewhat increased spacing allows the last valve to be placed at 6860 ft (compared to 6530 ft in case 1).

As in case 1, a total of 9 valves are included in the design.

A gas lift flow rate of 500 b/d is achieved.

The depth for valve No.7 if the static rather than the flowing gradient was to be used is shown by a dotted line at 5710 ft.

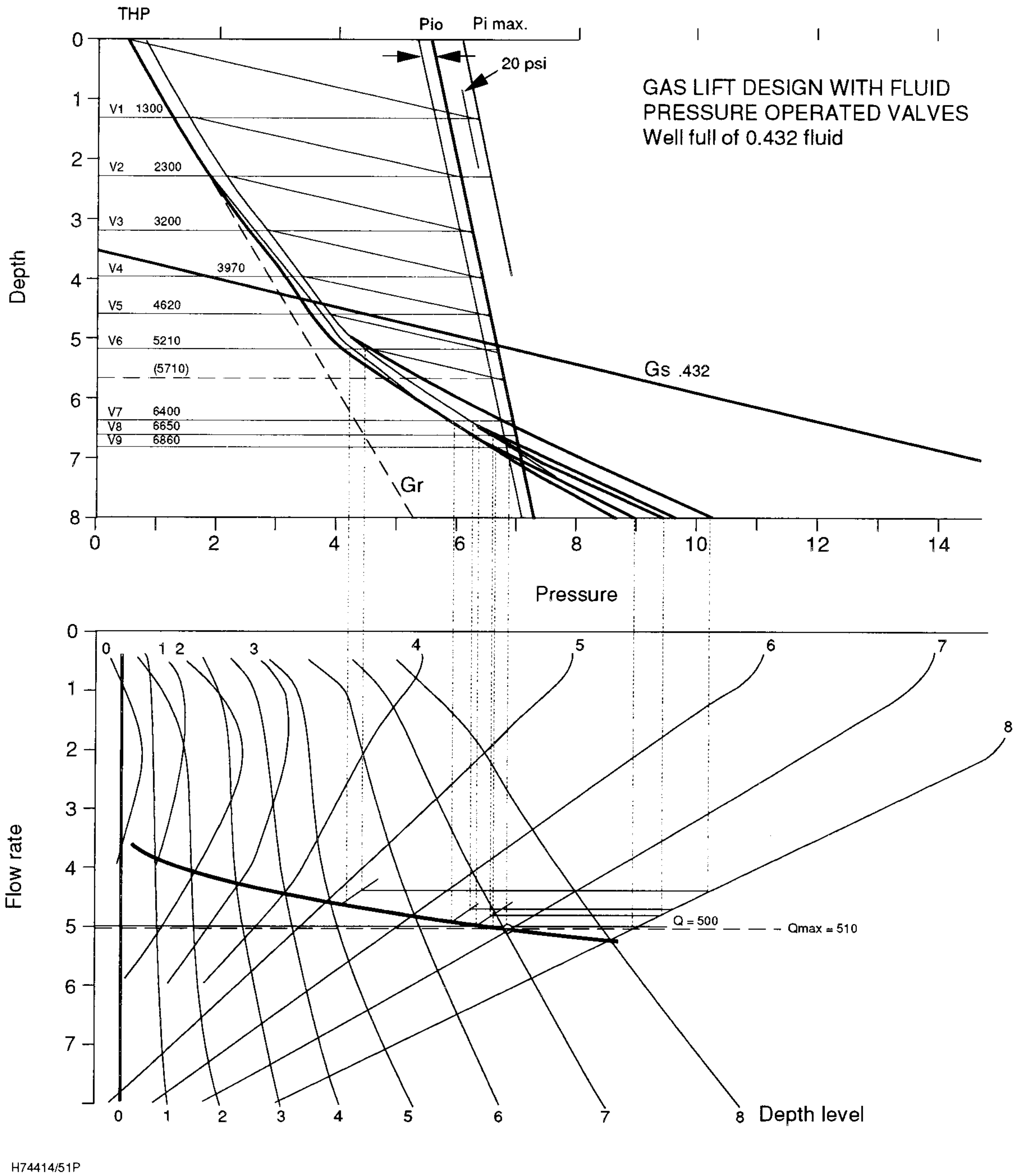


Figure C.7. - Case 6

C.2: DESIGN EXAMPLES FOR INJECTION PRESSURE OPERATED VALVES.

The same design data is used as that for the examples given in C.1 above.

C.2.1 Case 1:

Figure C.8. is an example of a gas lift design for gas pressure operated valves.

In this example the basic data used is the same as the data used to establish the boundary conditions depicted in figure C.1 so that this design can be compared with the designs for fluid operated valves.

Note: The gas injection pressure traverse starts at 550 psi. The pressure at depth is calculated using:

$$P_{id} = P_{is} \times \exp\left(0.01875 \times \gamma_g \times \left(\frac{D}{Tz}\right)\right)$$

where:

Pid = Pressure at depth, psia

Pis = Pressure at the surface, psia

γg = relative density of gas (air=1)

D = True vertical depth in ft.

z = gas deviation factor

T = average temperature in °R

Also note that the slope of the gas injection pressure traverse decreases as the injection pressure is stepped down, i.e. for each step in surface gas injection pressure a new gas gradient must be calculated.

The error introduced by using straight lines to represent the gas injection gradients is quite small in this and most cases. This is not necessarily the case under conditions where friction of the injection gas or temperature variation is significant.

The transfer pressures for all valves have been selected to be equal to the equilibrium pressure at each valve depth. Since the pressure decrement at each valve accounts for expected increases in tubing pressure at each valve, comparisons of the transfer pressures with the ultimate flowing gradient (as is the case in a PPO design) is not necessary.

The valves are selected such that they can pass the required lift gas rate at downhole conditions. The valve selection based on valve performance is an area of renewed interest and development. (Refer to section 3.6 for a general discussion on valve performance.) In this case the valves chosen are 1" valves with a 3/16" port that have a tubing effect factor (TEF) of 0.1.

The pressure decrement for the top valve is calculated using the additional tubing effect (ATE), shown in figure C.8 as 200 psi. Thus, the minimum pressure drop of the top valve is [0.1 x 20 =] 20 psi. (Refer to section 4.3.3 for a discussion of ATE and pressure drop.)

In order to account for uncertainty in the set pressures and design data, assume a design minimum pressure decrement of 25 psi. You can see that the other ATEs will be smaller so that a 25 psi pressure decrement is sufficient for all the valves, assuming that the port size is adequate. Larger port sizes require larger decrements since their TEF is larger. Although not considered in this design, larger port sizes may be required in the lower valves due to a smaller differential from the tubing to the casing pressure. This may result in an increase in pressure decrement required for lower valves.

The well completion will not contribute production until the pressure at the perforations falls below the static reservoir pressure. This occurs first during the transfer from valve 6 to 7, where the

equilibrium curve is less than the static gradient. Consequently, in this example, this is the first **(and only)** depth where the flowing gradient is used to locate the next valve, valve 7.

To maintain a 50 psi pressure differential across the last valve (in this case valve No.7) and allowing a 25 psi pressure drop at each valve, the final depth reached is 5340 ft compared to 6530 ft in the PPO valve design of figure C.2

The corresponding flow rates are 465 b/d for the IPO design and 493 b/d for the PPO design. It is pointed out that this difference is dependent, amongst many other factors, on the PI of the formation and on the difference between the natural GLR and the gas lift GLR.

In prolific, low GLR wells the effect of injection depth on achievable flow rate can be very significant.

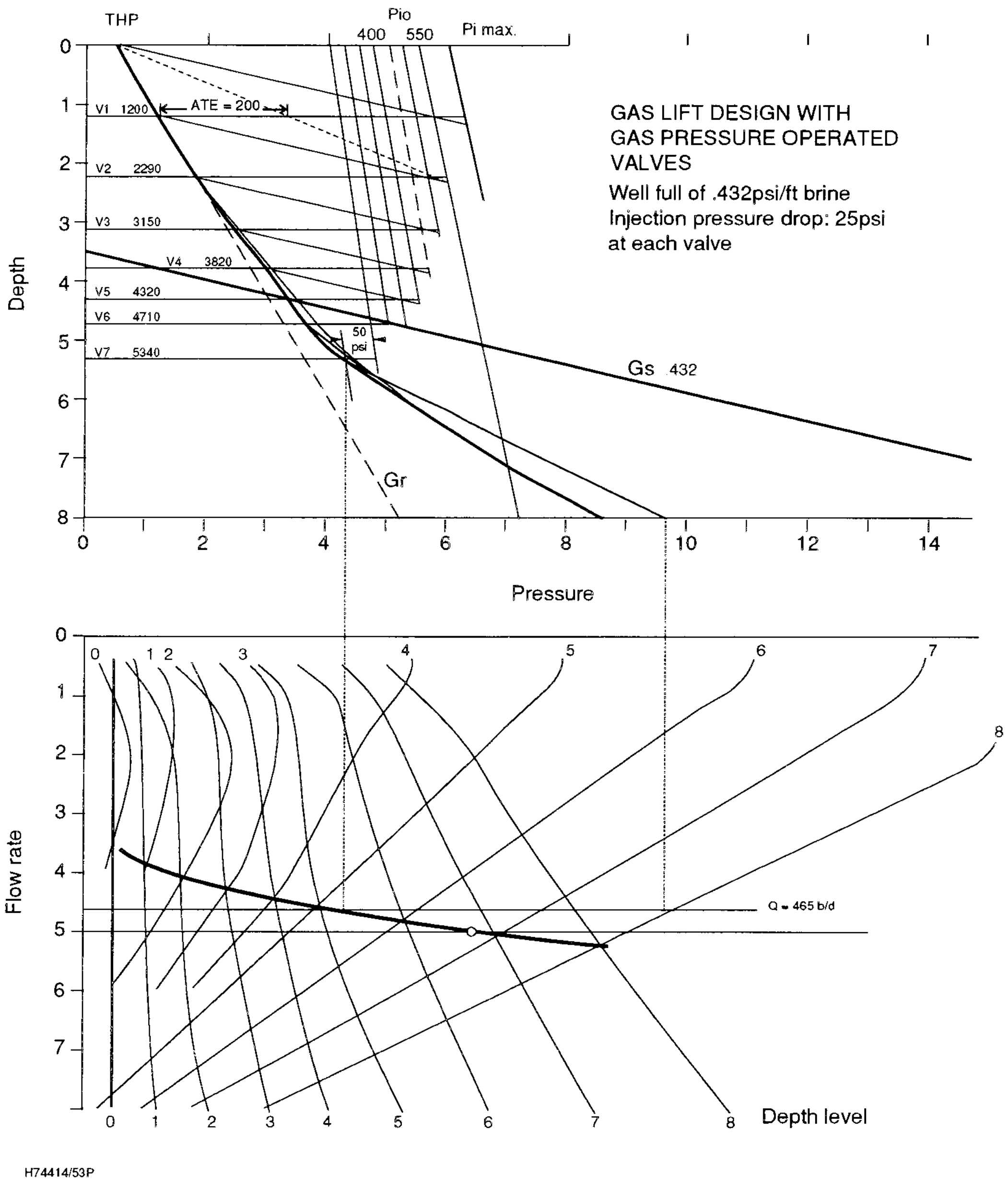


Figure C.8

C.2.2 Case 2:

Design a gas lift string for gas pressure operated valves assuming that the fluid level is allowed to stabilise.

Figure C.9 shows the worked out design for this example.

For a discussion on the position of the fluid level when pressure is applied to the injection string refer to case C.1.4. in the previous section on design for fluid pressure operated valves.

The position of the first valve is the same as in the design of figure C.5.

As from valve No.2 the design proceeds as in the example of figure C.8. However, note that the valves can be spaced to reach a deeper level because the well begins to flow after valve No.3 is reached and therefore the injection pressure available is higher because less valves have been used and hence less pressure reduction decrements have been required to reach that depth.

The flow rate achieved is 480 b/d when lifting from valve No.4.

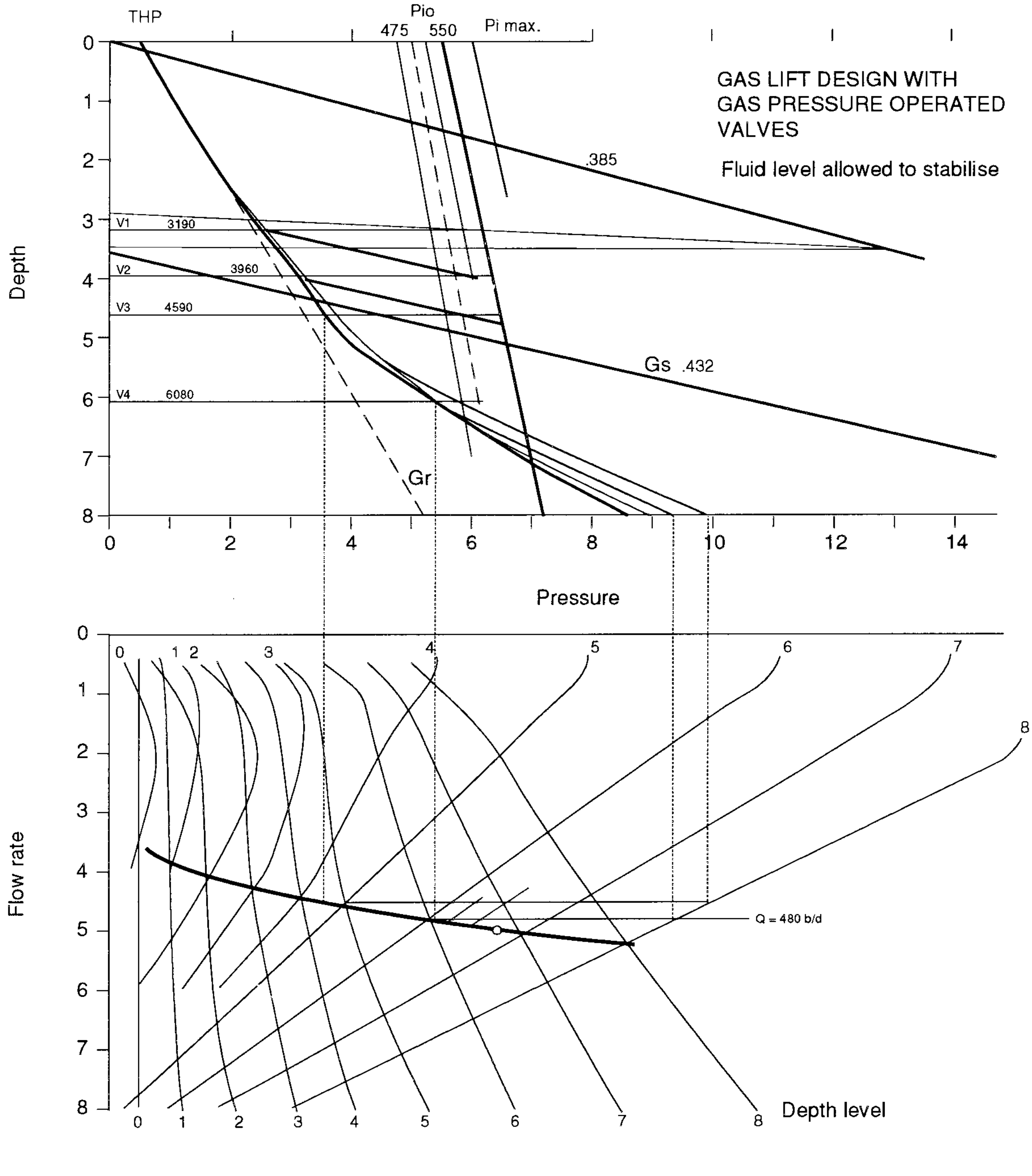

THP
Pio
475 550
Pi max.
GAS LIFT DESIGN WITH
GAS PRESSURE OPERATED
VALVES
Fluid level allowed to stabilise
.385
V1 3190
V2 3960
V3 4590
V4 6080
Gs .432
Gr
Depth
Pressure
Flow rate
Q = 480 b/d
Depth level
H74414/54P

Figure C.9.

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E. LIST OF ABBREVIATIONS.

ATE	-	Additional Tubing Effect
BHP	-	Bottom Hole Pressure
CAO	-	Computer Assisted Operations
Capex	-	Capital Expenditure
CHP	-	Casing Head Pressure
DCS	-	Distributed Control System
ESP	-	Electrical Submersible Pump
HP	-	High Pressure
IGLR	-	Injection Gas/Liquid Ratio
IPC	-	Inflow Performance Curve
IPO	-	Injection Pressure Operated
IPR	-	Inflow Performance Relationship
FTHP	-	Flowing Tubing Head Pressure
GLR	-	Gas/Liquid Ratio
GLUE	-	Gas Lift Users Environment
GOR	-	Gas/Oil Ratio
GUF	-	Gas Utilisation Factor
FGS	-	Flowing Gradient Survey
LP	-	Low Pressure
NGL	-	Natural Gas Liquids
NTO	-	Near Technical Optimum
Opex	-	Operational Expenditure
PAIL	-	Plunger Assisted Intermittent Lift
PI	-	Productivity Index
PLC	-	Programmable Logic Controller
PLT	-	Production Logging Tool
PPO	-	Production Pressure Operated
ROR	-	Rate of Return
SCADA	-	Surveillance, Control and Data Acquisition
SCSSV	-	Surface Controlled Subsurface Safety Valve
SSSV	-	SubSurface Safety Valve
TEF	-	Tubing Effect Factor
THP	-	Tubing Head Pressure
WePS	-	Well Performance Simulator